EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 18

DATE: Thursday, May 23, 1991

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

FARR & ASSOCIATES REPORTING INC.

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ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, on Thursday, the 23rd day of May, 1991, commencing at 10:00 a.m.

VOLUME 18

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
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MS. G. PATTERSON	Member

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---Upon commencing at 10:03 a.m.

THE REGISTRAR: This hearing is now in session. Please be seated.

MS. PATTERSON: Just before we start, Mr. Watson, I wanted to try to get clear this question of reserve margin and reliability that arises from page 9 where we sort of disregarded those three factors. I guess my question is whether you are using reliability and reserve margin to mean the same thing?

RONALD TABOREK,
DAVID BARRIE,
JOHN KENNETH SNELSON,
JUDITH RYAN; Resumed

MR. SNELSON: I think we have used reliability in a general sense and we perhaps should be more specific in terms of exactly when we mean reserve margin and exactly when we mean system minutes of unsupplied energy.

MS. PATTERSON: I think that would be helpful.

MR. TABOREK: In particular, it means it would require you to optimize at a higher reserve margin, to optimize at a higher level of reliability, which would be a lower system minutes.

lower s.min. if higher R.M & higher level of reliab.

MS. PATTERSON: It seems to me, just on a common sense basis, that higher reliability should lead

to lower reserve margins.

MR. SNELSON: There is a cause and effect here. If you want to have higher reliability, one way of achieving it is to have higher reserve margins, and that is one way in which things work.

If you are generating capacity, it naturally has a higher reliability because, say, the forced outage rate is low, then that may permit to you lower the reserve margin and achieve the same degree of system reliability.

So there are complex interactions here. And I think that common sense does work but one has to be very clear as to whether one is talking about the reliability of the individual generating units or the reliability of the system.

MS. PATTERSON: So, maybe we can try to be as specific as possible throughout.

MR. SNELSON: Yes.

MS. PATTERSON: Thank you.

THE CHAIRMAN: Mr. Watson?

MR. WATSON: Mr. Chairman, before we continue the cross-examination, today is the last day for motions on Panel 3 interrogatories. There is one outstanding interrogatory with Hydro, it's Interrogatory 3.9.1, I have had discussions with Hydro

counsel and I have been assured that we will have the answer in two weeks. It's fair to say that this is an important question for us and we are relying on that answer. I have informed Hydro counsel of this and they assured me that there shouldn't be a problem getting that answer within those two weeks.

On the assumption that that does occur, and I must say, we have had good success in the past, then I don't anticipate any need to come before you again. But if there is a problem I just want to put you on notice that we would have to come before you with a motion on this paticular interrogatory.

MS. HARVIE: If I could just follow up with that. We have answered all of the outstanding Panel 2 interrogatories with the exception of three, which I accept responsibility for. I held them back on Monday and said that the answers ought to be fuller than they were.

So the interrogatory that Mr. Watson is referring to is a supplementary interrogatory, one that his client had concerns with, we were providing some further information. We have had discussions with several other parties and we have some success so far in resolving their concerns well. I have been advised, just this morning, by Mr. Shepherd that they have a

number of concerns, as well and we will attempt to address those in due course.

THE CHAIRMAN: Thank you.

MR. WATSON: Mr. Chairman, I don't want to argue this. We are not agreeing that this is a supplementary interrogatory.

THE CHAIRMAN: No. They said they are going to answer, so I don't think we need to get into that issue.

MR. WATSON: Yes.

CROSS-EXAMINATION BY MR. WATSON (Cont'd):

Q. Panel 2 matters from yesterday, on the second last page of the transcript, that's page 3059 --

MR. SNELSON: A. I don't think we have the transcript available.

Q. I don't think you need it because you simply answered a question. "I'm sorry, I don't know the answer to that question." That's at page 3059, line 11 and 12. I am just wondering if we could get the answer to that question.

MR. TABOREK: A. I can give it to you right now, if you wish.

MR. SNELSON: A. I believe it's in an interrogatory. This is the contract limits on

interruptible power.

MR. TABOREK: A. Kenneth, it's how they are modelled.

MR. SNELSON: A. It's how they are modelled, I'm sorry.

MR. TABOREK: A. The question is how they are modelled. They are modelled similarly to the hydraulic and they actually use the same module of the program as an energy limited resource. And really, there are a number of other energy limited resources that we include in emergency measures which are, in essence, modelled the same way.

MR. SNELSON: A. The actual terms and conditions for this discount demand service which is the current name of our interruptible contracts, the actual terms and conditions are given in answer to Interrogatory 2.6.32.

Q. The question that followed that was: "Do you know the effect these limits would have on the target reserve margin?", and you indicated that you did not know the answer to that. Do you know the answer now or could we get that at some future time?

MR. TABOREK: A. We are making a list of all of those and we will answer all of those for you as quickly as we can.

Q. Thank you. Yesterday you confirmed that the 2,000 megawatts of off-peak was included in the F&D•model inputs and you stated that the off-peak energy can improve the reliability not just off-peak but in on-peak hours as well, by allowing the hydraulic energy to be saved for peak hours.

Does the modelling of this 2,000 megawatts off-peak in the F&D model have any effect on the hydraulic modelling in the F&D model?

A. Could you repeat that again, the last part of your question? Does modelling of this...

Q. Does the modelling of this 2,000 megawatts of off-peak in the F&D model have any effect on the hydraulic modelling in the F&D?

A. It has to have, but any effect, what do you mean by "any effect"?

Q. Could you tell us what effect it does have and how significant that effect would be?

A. The significance, no, especially not the significance. We did calculations with and without the 2,000 megawatts off-peak and my memory is - and it is fuzzy - I think there was something like 2 per cent involved in it. But what I will do again is verify that my memory is correct.

Q. And get back to us with the answer?

A. Yes.

Q. Thank you, Mr. Taborek.

Do the results of the peak shaving depend on whether or not the 2,000 megawatts is included?

A. Again, I can't give you that answer.

Q. You will get back to us?

A. Yes.

Q. Thank you. Do you know if the model just simply adds the 2,000 megawatts of off-peak energy to the available hydraulic energy before it does the peak shaving?

MR. SNELSON: A. I wouldn't expect it to. I think Mr. Taborek yesterday indicated that it was modelled as a generator. And if that was correct, then that isn't the same as adding it to the hydraulic energy.

MR. TABOREK: A. Again, I think, an undertaking.

Q. You will check all that and get back to us?

A. Yes.

Q. Is there a document that describes all of this, a manual or paper or something? ...

[10:14 a.m.] A. Well, you have our most recent manual.

MR. WATSON: Okay, thank you.

Mr. Chairman, Members of the Committee and the Panel, I'm still dealing with the global area of reserve margin. I'm turning to a new subarea of incapability factors in that main area.

Q. Panel, if you'd look at page 22 of Exhibit 137, that is page 7 of the F&D manual. Page 7 presents some formula dealing with the F&D model and its calculation of unavailability factors for the two-state model. One of the variables in there is FOR, that is F-O-R. Where do the values of FOR come from?

MR. TABOREK: A. FOR is forced outage rate, and these values would come from annual forecasts of reliability indices that we prepare, and the last three years of these reports have been introduced as evidence. I don't have the numbers in -- excuse me, have been in interrogatories, provided in interrogatories.

MR. SNELSON: A. They were provided in interrogatory 2.7.1. That was the 19 -- sorry, not 2.7.1.

Q. 2.7.81.

A. 2.7.40, sorry, 2.7.40 provided the

March '89 and the January 1990 versions.

Q. And the '90 was just put in the other day?

A. The '91. The early -- January or May '91 edition, which was current, was put in evidence just the other day.

Q. Which is the '90 forecast?

MR. TABOREK: A. Yes, the numbers, every report is prepared in the fall of the year, October, November.

Q. Yes.

A. So the '90 report would have been prepared in the fall of '90, and it is usually issued in the early part of the next year. So it is the report dated '91. That would be common to all three reports.

Q. In those reliability forecasts, for instance, in the '89 reliability forecast, tables 1 and 2 deal with DAFOR, D-A-F-O-R.

A. Yes.

Q. Are the DAFORs the values used here for FOR?

A. Yes.

MR. SNELSON: A. I would just want to just caution you a little bit. That is, this is the

manual as it was in the late 1970s. It doesn't necessarily correspond exactly with our current practice. So, the measure of forced outage rate that we currently use is DAFOR, D-A-F-O-R, as it is in the reliability indices reports that you have. The way in which they are combined together may have changed a little since the late 1970's. So, I wouldn't be prepared to accept these formally, exactly as they are, as being a current practice.

Q. This manual, though, is all we have right now?

A. Yes.

Q. So, I guess we are forced to work with this right now.

Could you provide us with the updated formula?

A. If there is a change in this formula, we will provide it.

Q. I got the impression from what you were saying that there was a change.

A. I see these factors like 7 over 5 and 7 over 2, and ratios like POSMOF, which I don't think are currently forecast. So, I suspect that this formula isn't exactly applicable.

MR. TABOREK: A. Having cautioned you

that we are going back and reading things that were written 14 years ago, one of the things that I may be able to say is that what this formula does is, it does two things to us. It is first of all a mechanism to allow in-service data uncertainty to be included in the model or not, and so some of these are switches to allow that to happen, in effect - to allow the computation to be done one way or another.

Now we almost always use in-service data uncertainty, the other thing is that we also have a factor called MOF, maintenance outage factor, which is a degree of maintenance over which you have some limited degree of time in which to schedule. And it could be scheduled beyond the next weekend. It need not be done immediately. So, there are three things, F-O-Rs, which are DAFORs and DAUFOPs have to be done immediately. MOFs you have beyond the next weekend in which to schedule it, and then POFs you have quite a large time, planned outage factors, a long time to schedule it.

What the MOFACT parameter does, it is a switch that allows you to shift MOFs to the weekends or not. And we always switch MOFs to the weekend. So, some of this is, in effect, still used, but not necessarily all of it just that way.

Q. You were referring to the forecasts. In the forecasts you also take care of DAUFOPs and UFORs, I believe -- UFOPs.

A. UFOPs, which get carried into DAUFOPs.

Q. Could you say that again, please?

A. I think, to go into English -- my colleagues said they would have my head if I got into MOFs, POFs and DAFORs.

It is important for us to know, to be able to categorize the outages that occur with our generating units. And we have quite an extensive list of outage categories, about a dozen or so, that are described in the reports. The ones that really matter are the ones that I really described to you to this point, the ones that matter here in this hearing. There are those which are forced on you which must be dealt with right now. Those are the ones that affect reliability.

Then there is a category called maintenance outage factors, MOFs. These are the ones I described, where you have some limited flexibility in scheduling them, typically beyond the weekend, and the precise definitions are in this.

Then, there are the planned outage

factors, which are the ones that could be extended, can be fitted in over some longer period of time.

The sum of those, simply speaking, is the incapability of the unit; how much time the unit is out as a whole.

I showed you graphs earlier of the behaviour of the nuclear, fossil and hydraulic systems, and I just simply labeled them "Forced" and "Total." The "Forced" was the forced outages, and the "Total" was force plus MOFs plus POFs. Force plus maintenance plus planned for the total.

The importance of those, the forced outages impact reliability because they hit you right now, and the total influences your maintenance requirements and your energy output from your system. So, it is important in energy. Plus you have to find time to do it all, which could influence your forced outages.

Those are the three broad categories. Now within forced there is, again simplifying, two categories. There is DAFORs, and what -- the FOR is forced out, the DAFOR is derating adjusted forced outage, and all it means is that sometimes you are not taken out totally, you are only taken out partially, so there is an adjustment made for that. ...

[10:25 a.m.] You don't lose all; you lose some of your units. So, it is a DAFOR, not a FOR. And that parameter is used when the unit is running almost all the time and it is forced out.

But some of our units are peaking units and they basically sit unused until called upon. And so, what is important is not whether it fails when you don't need it, but whether it fails when you need it. And so now they make an adjustment to the forced outage rate, UFOP, I think - utilization forced outage probability. What are the chances of that thing that has been sitting there unused coming on when you want it, which is the appropriate criteria for peaking units?

And then, there is the DAUFOP, which is the derated - introducing the derating aspect of that. And that the FORS here would normally be DAFORS and DAUFOPS. It is simply forced outages.

MR. SNELSON: A. This is explained at the back of the reliability indices reports that were given in answer to that interrogatory, if it was necessary. That is Interrogatory 2.7.40. If it was deemed necessary to get into this degree of detail, but we are going to a tremendous level of detail, I think, for the issue we are trying to talk about.

MR. TABOREK: A. And this particular question and this particular piece of the code, when you have a thing called -- when you have this MOF which you may or may not shift a short time, to use it, you would have to have in your computer code a little switch to say, am I going to shift it or not? And that is what the MOFACT is; it is a switch for that.

Q. What is the POSMOF?

A. It is defined in the computer code. You have the manual; it is defined in the manual.

MR. SNELSON: A. It is, in fact, defined, I believe, on that page that you have under Item 5 at the very top.

MR. TABOREK: A. Yes, okay.

Q. Well, it says, "Fraction of maintenance outage that will be considered."

MR. SNELSON: A. Yes.

Q. I am not sure that helps us an awful lot. Could you expand on that?

MR. TABOREK: A. To be shifted.

Q. From when to when?

A. From now until the weekend.

Q. To the next weekend? To any particular weekend?

A. You are taking me into a level that I

don't normally go to into the code. I think I would come back.

You have to say two things about mathematical models for generation reliability: One is that people have done some extremely sophisticated work on them to attempt to model very rare events occurring on a complex system, and they set up many cases, many things.

But having said that, these models have definite limits in the degree to which you should rely on your output. And again, the output is very much dependent on the sense of the input and the way in which you choose to use some of these parameters.

And so I think that --

THE CHAIRMAN: Perhaps it would help a bit - for me, at least - if you explain, Mr. Watson, just where this particular line of cross-examination is directed towards. What you are attempting to demonstrate by it?

MR. WATSON: Well, what we are trying to do, Mr. Chairman, is, again, look at what the F&D model is doing with respect to capability factors. And Mr. Snelson said something of interest; he said he didn't expect to get into this level of detail, and maybe that is going to be a clue for me, because later on when we

leave reserve margin, there is a whole area that I would suggest is of significance in dealing with the existing system, and that is the plant performance of the existing system. And needless to say, the only way you can properly address that is to get into the capability factors, and I was anticipating doing that in some depth.

Now, if this is not going to the appropriate panel to deal with this, I would like to know when I can deal with it, because I would suggest to you the capability factors of the various plants are of very great importance in a planning exercise for a host of reasons; just one right off the bat is to determine, for instance, your level of base load that you need and the units that are going to satisfy that base load.

MR. SNELSON: I believe on this panel, we are prepared to deal at a general level with predictions of availability and how that affects the reliability level in a general sense. As to the details of those predictions, whether a particular generating unit in the year 1996 will have a capability factor of 80 per cent or 85 per cent, then we would expect that that degree of detail would be discussed by the appropriate option panel.

So, we would expect that the details of thermal plant availability would be discussed in Panel 8 and the details of nuclear availability would be discussed in Panel 9, and the details of hydraulic availability would be discussed in Panel 6.

But obviously from a planning perspective, we are interested in the total availability, which, of course, is made up of details. The primary thing that effects the planning of the system is the total availability of the components of the system.

MR. WATSON: I will try and work within that and perhaps as we proceed we will get some idea of exactly where the envelope is and we can decide what we will deal with here and what we will deal with in the future.

Q. Mr. Taborek, I believe you indicated that MOFACT was a switch, if you will. Is that the word you said?

MR. TABOREK: A. I will look up the definition. Oh, I am sorry, I am looking at the wrong -- MOFACT, yes, it is a switch.

Q. That means it is either on or off. It has a zero/one value?

A. Well, I guess it -- oh, I am sorry.

MR. SNELSON: A. If you look at the previous page, the one that you referenced, and I have the whole exhibit in front of me.

Q. Yes.

A. If you look at page 6 of that document, and I don't recall how it is referenced in the hearing as to whether it is an interrogatory or --

THE CHAIRMAN: It is 141, I think; is that right?

MR. WATSON: Yes, it is.

MR. SNELSON: Okay. Then on the preceding page, which is page 6, there is a sub item, small Roman numerals iv, 4, which indicates that the maintenance outage factor, MOFACT, is specified in input data. The MOFACT is the fraction of maintenance outage - an MOF, maintenance outage factor which is performed on the weekdays. One minus MOFACT is the amount that is postponed to the weekends.

MR. WATSON: Q. So it is not a switch then?

MR. SNELSON: A. If it was --

MR. TABOREK: A. Well, it is a switch if you set it to zero and that is the way we use it as we transfer all the maintenance. I was going to say it is a parameter that you could set to any value. We use it

as the switch by setting it to zero.

That is why I went back to say, putting it in this way, people can use these things in different ways, to achieve various results that the program might not otherwise do. That is why I made that statement.

...

[10:35 a.m.] MR. SNELSON: A. This, I believe, is a very small point.

Q. Unfortunately, I don't have your expertise in this area, Mr. Snelson, that's why we have to ask these questions, and, hopefully, as we go through them, we will determine the significance.

MR. TABOREK: A. For us, we usually set it zero and all the MOF is transferred to the weekends.

Q. Is it POSMOF set to zero; is it a switch as well? It's also a fraction.

MR. SNELSON: A. We can take an undertaking on that, because I don't think either of us know the answer to that question and we would just be spinning our wheels to try and answer it.

MR. TABOREK: A. If I may, actually, if you look at the formula, and if you set MOFACT equal to zero, then it doesn't what matter what POSMOF is because the whole bracket that it is in is going to be equal to zero, I think, or is...

MR. SNELSON: A. No. It appears in the next formula.

MR. TABOREK: A. So, in the weekend, it's going to come off in the weekend one.

MR. SNELSON: A. I think we should merely give you the undertaking and get back to you on

that.

Q. Thank you. You mentioned MAF as well, monthly availability factors. Where do these values come from?

A. I don't know.

Q. You will get back to us on that. And, also, could you get...

A. If it is necessary we will get back to you on it, yes.

THE CHAIRMAN: Well, he thinks it is necessary, and so I guess it is. That makes it necessary.

MR. SNELSON: Fine.

MR. WATSON: Thank you.

Q. And again, if you could get back to me on this question, as well. I am interested in the whether MAF reflects variations in monthly availability owing to planned outages only, or are other outages accounted for, as well? And then, the third question would be: Where does the planned outage schedule on which this is based come from, for the short term and the long term? Thank you.

MR. TABOREK: A. Yes.

Q. The F&D model requires input values of average repair time for each generator. Do these

values come from the average forced outage duration table on page 31 of the '89 forecast reliability?

A. There are two. There is a statement and a question you made. The model doesn't always require the duration of outages. It depends on what you wish to calculate with the model.

If you are going to calculate duration of outages, yes, but if you are only going to calculate unsupplied energy, it doesn't. And as to where the data comes from, it is typically recorded in, again, the forecast of reliability indices and you have the page on page 23 of your exhibit.

Q. That's page 31 of the '89 forecast which is page 23 of Exhibit 137.

A. Yes.

Q. I did a quick check and it looks as though the '90 forecast has exactly the same page.

A. That's correct.

Q. With exactly the same numbers.

A. That's correct. If I may, I will just explain that, unless you're going to ask about it?

Q. Please go ahead.

A. Okay. The information ahead on this chart indicates that this chart is not updated frequently. Basically, we have not felt comfortable

with that portion of the model that deals with the calculation of durations and consequently we have tended not to use it.

It is not necessary to do our calculation. When we calculate expected unsupplied energy we only need the forced outage rates because it's that that you use in the economic optimization. And because we weren't comfortable with what the model was doing, we basically have not asked for those number to be kept up-to-date.

Q. When you say you are not comfortable, would one of the reasons you are not comfortable include the fact that in the first sentence you are only dealing with outages which last for more than 30 minutes and less than four weeks with deratings ignored?

A. Yes, and you can get some long outages, yes. That's one of the reasons.

Q. That's one of the reasons you are revisiting all of this?

A. That is a data problem, but some of our discomfort is also with the working of the model.

Q. Yesterday we were talking about the higher reserve margin which is attributed in part to the immature nuclear units. Do you recall that

discussion?

A. Yes.

Q. The reference is page 95 of the reliability review for 1991. Now, does this arise from higher values of DAFOR, MOF and POF in Table 16 of the '89 forecast reliability?

A. Well, the effect on reliability is in the DAFOR. Unless the MOFs and POFs get so large -- well, they don't. I won't go any further.

MR. SNELSON: A. I think we did indicate yesterday that there was a second effect, which is the modelling of in-service date uncertainty, which has an additional effect of indicating a lesser availability, effectively, of units very close to their in-service date.

Q. So that there are two effects?

A. Yes.

Q. Do the commissioning tests occur during or before the first years of the table, which is is Table 16 at page 24 of Exhibit 137? That's the forecast of reliability indices for the future nuclear stations, Table 16.

THE CHAIRMAN: What is the source of that table? I'm sorry.

MR. WATSON: That's the 1989 forecast of

reliability indices.

THE CHAIRMAN: And what exhibit is that?

MR. WATSON: I am not sure that is an exhibit.

MR. TABOREK: It's again in Interrogatory 2.7.40.

MR. WATSON: I can make that an exhibit right now.

THE CHAIRMAN: No, no. I am just making a note of where the source is because sometimes it is helpful to look at the other pages in the document.

MR. WATSON: The Clerk has copies, so we can make it an exhibit right now, if you like.

MS. PATTERSON: We have copies attached to Interrogatory 2.7.40; right?

MR. WATSON: Yes.

THE CHAIRMAN: All right; that's good enough.

MR. SNELSON: I think the answer to your question as to whether the commissioning tests precede these forced outage rates is that the forced outage rates apply from the commercial in-service dates of units, and the commissioning tests precede those in-service dates.

MR. WATSON: Q. So, it would be before

then, it would be before the dates in these tables?

MR. SNELSON: A. Yes, these data apply from commercial in-service.

Q. Just quickly, could you confirm that the inputs used in the F&D model for the analysis presented in the '91 reliability review came from the '89 forecast?

MR. TABOREK: A. That is correct.

Q. As opposed to '88 forecast?

A. That is correct.

Q. What figures were used in the DSP, the '88 figures?

MR. SNELSON: A. The analysis you are referring to would be the reliability analysis that is in the plan analysis document on some preliminary cases for the DSP. And I presume that would be the values prepared in late '88 and published in early '89.

MR. TABOREK: A. There is usually a listing of assumptions. Here we are. Yes, on page 3-15 of the plan analysis, I am not sure what exhibit it is -- Exhibit 6, generating unit data, 1988 forecast of reliability indices.

Q. When Mr. Snelson was answering that question, he indicated that was used for some preliminary plans?

A. Yes.

Q. Are you saying that this was now done more generally?

A. No. I was describing the preliminary plans. The sequence here is that as we got into the Demand/Supply Plan exercise and before we knew the outcome of the Demand/Supply Plan, we went through our reliability process to take our 25 system minute criterion converted to reserve margins. We did that and we then used those reserve margins to develop the plans. And it is that initial process that is described in Chapter 3 of the plan analysis.

Since then, time has passed on the one hand, numbers have changed, and on the other hand we have for information, we have completed the planning process and we have more information about the future and so we have redone the calculations and that is reported in Exhibit 87, the reliability review that we have been talking about.

So it's those two pre-DSP, post-DSP reliability calcs, and then we often talk about a 1981 set of calcs sort of earlier on, that's reported in the another exhibit. So, there are three time periods in which these were done.

Q. The '89 values were used for 1991

reliability review. Can you tell us what the impact would be if you had used the 1990 figures in that reliability analysis?

A. There is a small increase in the forced outage rates in 1990 compared to 1989. It varies with time and there is not much difference between the '88 and '89 numbers.

I think I may be able to show you. I will have to show you three stages, because it's different for each of the types of generation.

Q. Mr. Taborek, I don't want to interrupt you; we can read the forecast to determine what the actual numerical differences are--

A. Okay.

Q. --in the values. I was more interested in what the bottom line would be, what is the overall difference in reliability and reserve margin?

A. I am sorry I can't give that to you right off. Because the forced outage rates were slightly higher, running it now other things being equal, would cause a small increase in the required reserve margin.

MR. SNELSON: A. There is a way of very roughly estimating it and that is that if forced outage

rates are in total -- if 1,000 megawatts of plant has an increase in its forced outage rate by one per cent, then that will create a need for somewhere around 10 or 12 megawatts of additional reserve. It's a little bit higher than the one per cent of the 1,000.

...

[10:50 a.m.] Forced outage rate on average, you lose one per cent of your capacity, then the effect on reserve margin is just a little bit larger than that one per cent of the capacity. So there are rough estimations that can be made.

Q. Thank you. And no doubt you will be doing that analysis, and if, in fact, your rough estimate is incorrect, you will let us know?

MR. TABOREK: A. Well, these -- we wouldn't actually redo our analysis for just the reason of one forecast changing. I mean, forecasts change all over the place, all the time. You can never stop rerunning your models. It is what you expect, and it is what the margin is for.

You are really looking for quite large, significant changes and often several of them, so that you are getting a really significant input, rather than, in effect, forecasting variations.

Q. Could we leave it this way then? Could you look at it tonight, and if, in fact, it is something substantially different than the one per cent you were just telling us, that you will let us know?

MR. SNELSON: A. My one per cent was an example. It wasn't indicating that there was a one per cent increase in forced outage rate. All I was saying

is that if you read the previous forecast and compare it with today's forecast, and for each generating plant you take the change in average availability due to the change in forced outage rate, and you add them all up and add a little bit, you will get the approximate effect on reserve requirement?

MR. TABOREK: A. You can just look at the three reports, measure the differences and apply that factor, and you will have it.

Q. Let's do it this way then. If you could look at it tonight, then let us know tomorrow what, in fact, the difference would be if you used the '90 numbers instead of '91. I'd appreciate that.

A. We may be able to provide you an estimate. It wouldn't be a calculation.

Q. An estimate is fine.

One last question, before I leave this area. What would be the impact on figure 5.1 of changing the reliability indices from the '89 values to the '90 values?

A. The sloping line, which is, in effect, reflecting the unsupplied energy which shift to the right, --

Q. Which shift to the right?

A. To the right.

MR. SNELSON: A. If the forecast rate outage rates were higher.

MR. TABOREK: A. Which would cause you to optimize at a higher reserve rate.

Q. Thank you. I'd like to move on to another area of load factor.

Does the F&D model use as an input a 24-hour load shape for a typical day, or only a daily peak?

A. What it does is it utilizes three load shapes: One for weekdays, one for Saturdays, one for Sundays for each month, so three per months, times 12 months for 36 months. So, it is 36 load shapes. And then it utilizes a duration curve of peaks for each of those load shapes, I believe. Yes, a duration curve of peaks for each of those load shapes.

MR. SNELSON: A. The daily load shapes Mr. Taborek refers to, do have 24 hours in them. So, they are the full load shape for the day, not just peak hour of the day.

Q. If you could refer to page 25 of Exhibit 137, which is page 58 of the 1991 reliability review...

THE CHAIRMAN: That is '87, is it?

MR. TABOREK: Yes.

MR. WATSON: Q. You see the second last sentence on that page reads:

"For example, using the simplified LOLE technique mentioned earlier in this chapter, it was found that decrease in the ratio of average daily peak to monthly peak by five per cent results in about a five per cent decrease in reserve margin requirements."

Could you tell us how that sensitivity analysis was done?

MR. TABOREK: A. We were attempting to get a rough cut at the effective load factor on reserve margin, and, essentially, it took some normal distributions and attempted to modify them to reflect the load factor. That is what is reported here.

Now when you flag this, I think there is something strange here. This number seems too large to me.

Q. Which number is that?

A. That a five per cent change in load factor would cause a five per cent change in reserve margin. So, what I'd like to do is go back and take a look at this.

Q. Thank you. If you could do that and

then let us know either this afternoon or tomorrow. I was going do ask you a series of questions on that--

A. Oh, okay.

Q. --with respect to whether -- well, I won't get into them now. Why don't you...

A. We will elaborate on the information we give you then.

Q. Well, perhaps I could ask you this. These were, in effect, a series of methodological questions. Would you be in a position to answer those?

A. It is difficult to answer your question as posed, since I don't know what they are. The easy ones, yes.

Q. Tell you what, why don't we defer these questions until you can get back to us with a correction for that statement?

Just before we leave that, can you give us some idea of what your discomfort is with that statement?

A. It looks too high.

Q. There are two fives.

A. The two fives, yes.

Q. Both those fives look too high?

A. Well, no the first five is an input in effect, and it is the output five, the second one,

that looks a bit high.

Q. What would you think it ought to be?

A. I'm not in a position to say at the moment, but I will be shortly. When they pointed it out, I set some work going on it.

Q. How are the inputs, the load shape inputs to the F&D model, constructed?

A. The load shape inputs. Well, we would have -- no, I think rather than attempt to answer generally, I will take that under advisement. Unless... Ken?

MR. SNELSON: A. I can remember, in general, how it is being done. And that is it is being done by analysis of actual load shapes from past data. And so we do, from time to time, recalculate the load shapes based on an analysis of actual load data for historical years.

Q. In addition to the day types, I believe yesterday you mentioned scaling factors, 101 scaling factors, did you not? Regardless of whether you did or not...

MR. TABOREK: A. Yes. I didn't think I did.

Q. Could you tell us how these 101 scaling factors, how are they representing the

probability distribution of peak demand within each day type which is constructed?

A. Basically, we will take -- the day types are normalized, and then...

Q. Normalized to?

A. To a unit. So you are quite right then. The peaks then come from the peak duration curve, and they are basically determined by using five years of data for that day type, to give -- and since you are doing this for every month, and there are, say, twenty weekdays in a month, and you take five years of information, you get roughly a hundred points on your duration curve, a hundred and one.

Then the weekends, there are not that many days, so you have fewer points, but we interpolate to around a hundred. And then those factors are applied to the normalized load shapes.

Q. Do those factors represent weather-related load uncertainty or long-term load uncertainty or both?

A. Those factors don't.

Q. Are there factors which do?

A. The load forecast uncertainty is introduced in addition to that, and it is the load forecast uncertainty that includes the latter two items

that you mentioned.

Q. We were talking about the probability distribution when we were discussing the scaling factors. Are these distributions the same for each month within the year?

A. No, they would be different for each month, I believe, because you pick the days appropriate to the month, and you have one for each load shape.

Q. Based on the historical data?

A. Historical data, yes.

Q. And actually the same answer would apply with respect to year to year data as well? You are not assuming same distributions each year, you are...

MR. SNELSON: A. In the future, we generally have no reason for saying that the probability distribution of peak loads will be different, say, in 1996 to what it will be in 1997. So, the shape of the curves will be the same for each year, but the peak of the curve will be adjusted to the peak load in the load forecast to account for load growth. So, all the shapes generally stayed the same after the future, but they are scaled up according to the forecast of load growth.

Q. Mr. Snelson, you mentioned yesterday

the LMSTM model. Are the same load shapes used in the F&D model as used in the LMSTM model?

A. No.

Q. How are they different?

A. The structures of the models are different, and therefore they require different definitions of load shape.

Q. You mentioned that the F&D model derives its input for this area from historical data. Does the same data set supply the input to the LMSTM model. The LMSTM model is also based on historical data and analysis of historical data.

Q. So it is the same data set, just different inputs are created?

A. I cannot be definite that it was the same years of historical data that were used as the basis.

...

[11:04 a.m.] MR. TABOREK: A. And a special feature of LMSTM is it uses data by different classes of load and it builds load shapes. And so it is quite a different model.

Q. Would it be appropriate to use an end-use model to determine the load shape for a reliability model?

A. Well, you would have to say it depends.

Q. On?

A. On the model, the data, the job you are doing.

MR. SNELSON: A. It depends on whether you have enough data about the characteristics of the end uses to be able to combine them together in a useful way. I think that in Panel 1, the indication was that the end-use load forecasting model is primarily an energy model and that they are proposing, I believe, to do some work to enable it to forecast peak loads as well.

To actually be able to make it useful for a reliability model, you would not only have to be able to forecast the peak load, but you would also have to be able to forecast the variability of the peak load.

So, I think that the end-use models that

we currently have are, at least, two major development stages away from being able to be used for a reliability analysis.

Q. Is it fair to say that system load factor is related to the load factor of the three sectors; that is industrial, residential and commercial?

A. That is one way of describing it.

Q. Is it also fair to say that, as the load factors for the three sectors change, so does the system load factor?

A. Presuming the changes are not offsetting, yes.

Q. I understand that, currently, industry has a high load factor and residential has a low load factor.

A. Certainly a lot of industry has a high load factor. I would presume that the other classes have lower load factors, but I haven't looked at the data recently.

Q. I also understand from Panel 1 that the Hydro load forecast department has forecasted changes in the various sector load shares. If that is correct, how is that accounted for?

A. What is accounted for in our models

is the energy demand that is forecast in the load forecast and the peak demand that is forecast in the load forecast. And those to two things define load factor.

I am sure there has been considerable discussion with Panel 1 as to their methods of coming up with their peak and their median load forecast.

Q. How does that relate to you? The load forecasting people do what they do; how does that relate to you people?

A. We use load shapes, peak load duration curves, so as to match the peak forecast of the load forecast and to match the energy demand of the load forecast.

Q. What is the smallest unit of time in the F&D model? Is it one hour or 20 minutes?

A. One hour.

MR. TABOREK: A. With one modification: We enter 20 minute loads, but there is a pre-processing program that converts them to hour and so it uses one hour.

Q. Okay. If it uses one hour, how does it handle the 20-minute system peak that we have heard so much about?

A. By using an equivalent one hour. And

the difference, incidentally, between the 20 minute and the one hour is fairly small. I think it is about 200 megawatts, if my memory serves me right.

MR. BARRIE: A. Perhaps I could add, yes. In response to the question earlier, we did some analysis on the difference between instantaneous 20-minute and one-hour peaks. It depends on the particular day, of course, so it can vary, but the difference between 60- and 20-minute would appear to be somewhere between 50 and 250 megawatts, depending on the particular day.

I could add as well, the difference between instantaneous and 20-minute. Although we don't record instantaneous all the time, we have visually seen it, and we would suggest that the difference there is somewhere between 50 and 150 megawatts, depending on the peakness of that particular day's operation.

MR. TABOREK: A. To put that in perspective, those are parts of about 24,000 megawatts.

Q. So, for each hour you use a 20-minute number?

A. No, no. I think I am just outlining for you the process by which data is prepared for the F&D model. And I think you may have seen written up in the manual the fact that 20-minute peak data is input.

Well, it is quite true it is input, but there is a processing module that converts it to hourly peaks and the hourly peaks are actually used in the calculation. That is why I wanted to make that distinction.

Q. Panel, if you could turn to page 26 of Exhibit 137.

And Mr. Chairman, I am now turning to some questions on the environmental limitations, which are at Section 4.7 of page 83 on Exhibit 87. And what you will see on that page are a number of environmental limitations that might impact reliability are mentioned. They include reducing the net output of generating units, increasing the forced outage rate of fossil-fired units, forcing several units out of service leading to transmission constraints resulting from abnormal operation of the system during air pollution episodes.

Can any of these situations arise under existing regulations?

A. Yes, they can. The first item, for instance, reducing the net output of generating units, Ms. Ryan mentioned that we had installed devices called flue gas conditioners on our major fossil plants. The purpose of these devices is to allow the precipitators

which remove dust from the flue gas to operate as well with a lower sulfur coal that we were using to reduce acid gas emissions as they do with the higher sulfur coal for which they were designed. We were pushing them beyond their design so we were augmenting them with this new technology.

And so the output of a generating unit is limited by an opacity limit, which Ms. Ryan again defined.

Now, we had trouble getting those flue gas conditioners to work properly. And for some period of time -- your recourse then is to derate the units so that they are not sending up as much dust so that the precipitator is working not as proposed, would be able to stay within the opacity limits.

So, in order to meet the present emission limit and opacity limits, the present opacity limits, we had to suffer a derating until such time as we got those devices working properly.

Q. Are there any other examples?

A. Now, the present, with the same regulation as we now have or really any SO(2) regulation, we are now going ahead, as Ms. Ryan again described, fit two scrubbers on Lambton, and other scrubbers are featured in our plans.

The scrubber is, in effect, a large factory, a chemical factory, and a chemical factory requires power to run and it basically takes that power from the generator that it is cleaning and reduces the available power of that generator by roughly one per cent, I think, but that is recorded somewhere in these pages close behind. And again, depending on this type of scrubber, anywhere from .9 to 1.5 per cent of the power output of the generator is required to run the scrubber.

Q. You have described a couple of situations, Mr. Taborek. Has Hydro done any analysis to evaluate the potential impact of these existing regulations on system reliability?

A. When you use the words "any analysis," it is a little bit too broad to answer.

Q. Well, can you just --

A. Could you narrow that down a bit, please?

Q. Can you tell us what Hydro has done? (Laughter) I am not trying to be facetious.

A. Okay. Basically, the reason I am hedging is you can't analyze anything without analyzing reliability impacts. You have to look at reliability, energy, cost, et cetera. You always look at all of

them at all the same time. But if you say, did we do special F&D runs to determine the impact of scrubbers on reliability, no, we didn't.

Now, what we did do is, we introduced the effect of scrubber unreliability into the forced outage rates of the fossil generating units. And we also, when we do our calculation - well, any calculation - you recognize the lost capacity and the associated costs.

Well, I think that is the answer.

Q. So, is it fair to say then that while you don't do any specific runs of the F&D model, you do use your judgment to --

A. Actually -- I am sorry, I shouldn't interrupt.

Q. You do use your judgment to adjust some of the inputs?

A. There is another factor. We will use - for instance, when we know there is an effect of one per cent say on a forced outage rate - Mr. Snelson gave you a rule of thumb that allows you to do a quick assessment of the impact and you just do that automatically. You wouldn't do a whole computer run to do that; you can do it in your head and you can work with that.

Q. We were talking about system reliability. What about the target reserve margin?

A. Well, again, the target reserve margin would be affected, but this would be in the nature of -- I mentioned to you earlier that there are thousands of parameters that attempt to describe the electrical system. There are millions of parameters that describe it in real life.

And at any point in time, those parameters are changing all the time. And unless there were some -- you sort of don't analyze every time a parameter changes. You wait for really significant changes or significant groups of changes or some particular study requiring certain information and you would do it then.

MR. SNELSON: A. One of the remarks that Mr. Taborek made in his direct evidence yesterday was that the effect of running into our SO(2) limit is not modelled in our reliability calculation.

And the reason for that he explained, is that the reliability calculation is being done to decide how much generation capacity is required on the system.

...

[11:20 a.m.] If you run into the SO(2) limit, the solution is not to build more generating capacity usually; the solution is usually to add more SO(2) controls to existing generating units. So, that's the reason that in the reliability calculations, the SO(2) limit is not considered to be a constraint.

Q. So it's not a constraint, because you are going to do what has to be done to those units to ensure that they meet the limit?

MR. TABOREK: A. Yes.

MR. SNELSON: A. Yes.

MR. TABOREK: A. There is another undercurrent that comes back to some statements that we made earlier, that we have gone through many areas of the model and we have noted areas in which the model is very good and areas in which it has deficiencies.

I think one of the things you are seeing from us, that we don't run the model all the time and use the model as our sole basis for decision-making, because we are basically exercising judgments about how much it can be relied on compared with experience, compared with similar calculations, compared to what other people are doing. You seem to be expecting us to run the model more as if everything depends upon the model. It is just one of the tools that we use.

In this area of reliability, I have heard people say this, but this area of reliability is one where this is especially true because of the difficulty of modelling this complex situation and these rare events, and I don't mean to demean the model by saying that either.

Q. No. It's a tool and you use that in conjunction with your judgment based on your experience, your knowledge of the system, and you come up with a figure that you feel is reasonable.

We have been talking about the existing regulations and whether any of the situations described on page 83 of the reliability review can arise. What about the proposed regulations? I assume that if these situations can exist and arise under the existing regulations, even more so can they arise under the proposed regulations.

A. Well, this is especially difficult to answer because you are asking for a hypothesis. And when you are looking at regulation a word or a comma can cause an enormous difference in how you react. One of the purposes of making a proposal and making it public is to invite comment. It's been my experience that governments have usually taken comments and weighed them in the light of what they wish to achieve

and what it costs society to get there, and they usually make some very sensible adjustments. And I act on the basis that that will continue to occur in the future. You have to wait and see. You are not sure.

And there is a tendency -- early on, when I opened my discussion, I made some very elementary comments about peak is power in an instant and it has no energy and no emissions, and energy is power over a long period of time and that's where the emissions are.

It's very tempting for legislators to say, "There's a coal plant, put a scrubber on her," or "There is a coal plant, do this," without checking to see if it produces any emissions or not. And it's tempting to want to sort of apply blanket rules to some other criteria which doesn't recognize how much emissions or things like that come from plants, and if those kind of laws were to go in place, it would have a serious effect.

But I believe, the experience I have had with governments is that they do recognize those effects, that you are getting no gain and enormous cost, and so they do tend to adjust the regulation suitably.

Q. What lead time is required between the adoption of a new regulation that would have any of

the effects listed above, that's the ones that we have been discussing, and construction of new generation if that was required to mitigate any of the adverse effects on system reliability?

A. Well, the lead times, the lead times that we have put forward for the DSP, are in Chapter 15.

MR. SNELSON: A. 14.

MR. TABOREK: A. 14. And for our purposes, we have notified that once we have approval, we, on the reliability side, are planning for CTUs for a 4-year lead time, but that those are not energy-producing devices; those are capacity-producing devices for peak.

I presume, since you are looking with emissions, you are looking at energy-producing devices and so you are looking at lead times appropriate to base load rather than peak load generation.

Q. If we are interested in the reliability impacts at the moment, should we not be talking about the lead time for, say, a gas turbine?

A. If the problem you are dealing with is a capacity problem, the blip, the hour, et cetera, but if you are saying an environmental regulation has been applied and it's affecting base load plant and

that's the problem, then you are looking for base load plant to replace it.

Q. And if that's the situation, you are not talking CTUs, you are not talking a 4-year lead time; you are talking base load units, nuclear or large coal.

A. Yes.

Q. And you are talking considerably longer leads times; is that fair?

A. Yes.

MR. SNELSON: A. Just to correct myself, the lead times are actually given in Figure 15-6 of Exhibit 3 which is chapter 15, not chapter 14.

Q. Thank you, Mr. Snelson.

Has Hydro done, or is Hydro planning to do, any analysis to anticipate and prepare for any adverse effects on system reliability resulting from future environmental regulations?

MR. TABOREK: A. Yes.

Q. Can you tell us what they are?

A. What we do is we analyze the regulations that are being proposed and provide comments to the governments that are proposing them in such a fashion that they can achieve their objectives at the least cost as far as they impact on our

generation.

Q. Can you tell us two or three of the more important proposed regulations that you are looking at right now?

A. There are proposed regulations developed by the federal and provincial governments working together to control NOX and VOCs, volatile organic compounds.

These particular regulations, as they affect NOX, would for generating stations in the Windsor to Quebec corridor, and in Southern British Columbia where there are high NOX levels leading to VOCs, as I understand the chemistry, impose a regulation that what is written in terms of fossil-fueled units - and this a loose translation - shall not exceed -- I am not sure if it's 100 or 200 nanograms per joule of heat input, I think. But the specific numbers aren't important.

The effect of this is that it is a regulation that would not discriminate between whether a plant was a base load unit producing a lot of emissions or a peak load unit producing little or no emissions, and it would not discriminate between whether this was a brand new plant or a plant in the last year or two of its life.

And the effect of the number that's in there is to cause, in effect, a device called selective catalytic reduction to be fitted to control the NOX.

Now, regardless of the jargon that describes it, what it is, it's a large capital cost item to remove roughly 80 per cent of the NOX.

What we are essentially noting, and this is a point we continually have to note in regulations, that if you put a large capital cost on a unit which produces a lot of output and which has a long life ahead of it, the capital cost is written off over a long period, it can be economic.

If, however, you put the same capital cost on a unit that is a peaker, that seldom runs, that produces little in the way of emissions and that has a short life attached to it, to sort of make the extreme case, that plant becomes decidedly uneconomic, and if you were to push that regulation, you can achieve -- well, you will basically spend a lot of money removing no emissions, is what it boils down to.

MS. RYAN: A. If I could just expand on what Mr. Taborek has said. That is a good example because it's the development of regulation where government has in fact participated in a consultation process with provincial, federal governments, with

industrial associations and with environmental interest groups. And the first form of the regulation was in fact a per unit emission per unit of energy type of regulation. And after such discussions that if we want a cost-effective regulation to reduce the most nitric oxide we can for the least amount of money, that there were other options.

The consultation process seems to be leading to a regulation that will in fact be an emission cap for an industrial sector or an industry. An they can then decide the most cost-effective way to reduce their emissions.

So we are at the process now that we are expecting that we will be expected to reduce our NOX emissions in the future, but we are still at the process of discussing, so we really don't know what the level would be or the timing will be, but certainly, it looks like we will have more flexibility in the options we use to reduce our emissions in the future.

MR. TABOREK: A. There are other regulations and they often fall into that very same trap of confusing peak and energy.

MR. WATSON: I was going to turn to another sub area, Mr. Chairman.

THE CHAIRMAN: Fine.

We will take a 15-minute break.

THE REGISTRAR: This hearing will recess for 15 minutes.

---Recess at 11:32 a.m.

...

---On resuming at 11:50 a.m.

THE REGISTRAR: Please come to order. This hearing is again in session, please be seated.

MR. WATSON: Q. Still dealing with reserve margin, moving to a subarea dealing with emergency actions. Panel, if you could refer to Exhibit 137, page 26A. That is page 84 of Exhibit 87. Excuse me, that is page 26B, Table 6.3, the next page.

THE CHAIRMAN: That is 103 of 87?

MR. WATSON: Yes.

Q. This table shows that there are 2500 megawatts of emergency measures available. That includes 200 megawatts of general public appeal and 200 megawatts of limited industrial appeal. The next page of that exhibit is page 105, and near the top that...

THE CHAIRMAN: Which is again 87 is it?

MR. WATSON: Yes, that is page 105, Exhibit 87.

Q. At the top of that page, that says:

"About 1,000 megawatts of different types of public appeals are available."

Panel, could you help us out as to the correlation between the 1,000 megawatts of public appeals that are mentioned on page 105, and the 400 megawatts of appeals that are mentioned on page 103?

MR. TABOREK: A. Just give me a second, please.

Q. Certainly.

A. There is either of two possibilities. While you see on Table 6.3, page 26B, 200 and 200 megawatts totaling 400, which is roughly 2 per cent of the load or 2 per cent of the margin, you will see on page 28 an expansion in Table 4.7.

THE CHAIRMAN: Page 28, of what document?

MR. TABOREK: That is the same exhibit, it is just a few pages on.

THE CHAIRMAN: So, that is page 98 of 87.

MR. TABOREK: 79.

THE CHAIRMAN: Oh, sorry, 79.

MR. TABOREK: The written number is 28, and the printed number is 79.

MR. WATSON: Q. That is Table 4.7?

MR. TABOREK: A. The first two, the general public appeal and the limited industrial appeal are here in percentage terms, but that is your 200 and 200 megawatts.

Q. Those figures are roughly equivalent, that is what you're saying?

A. Yes.

Q. One per cent for each of those

corresponds roughly to 200 megawatts?

A. To 200 megawatts, yes. Then the full industrial appeal would add another three per cent. So, option 1 is that the 1,000, I think, corresponds to a full five per cent, and that 1,000 may refer to that.

Now, if that is the case, there is another option. Possibly it is a typo, because this is written really talking about the 400, and so I think we should put 400 on that page instead of 1,000. So I'm not sure of the exact reason, but the -- no, this -- it should have 400 to be read properly.

Q. Well...

A. Because it is about that table, and it is not about the larger one.

Q. Isn't there a third option? Isn't the third option that if you look at Table 4.7, which gives 5 percentage points of appeals, then you refer to page 105, which talks about the 1,000 megawatts, which would seem to correspond to Table 4.7.

A. Okay.

Q. Then wouldn't the third option be that Table 6.3 should be increased by 600 megawatts?

A. No, no, definitely not.

Q. That is not a third option.

A. No, that is not a third option,

because...

Q. Why wouldn't that logic flow, that I just went through, apply?

A. If you go back to Table 4.7 again, you will note the text that follows it says, in effect, that the full industrial appeal is, in effect, a load cut, and that it is not without cost and hence should not be included in the category of appeals with little or no cost.

THE CHAIRMAN: Where are you reading that from?

MR. TABOREK: Again on page 28, written -- it is below Table 4.7, and it is the paragraph below, where it describes the different types of appeals. And the paragraph is in effect saying that we will only consider the first two types as emergency measures without cost, because the third type is, in effect, a load cut with notice, I think is the term. And that it does have a cost associated with it.

So it is properly categorized as a load cut, and not a little or no cost emergency measure.

MR. WATSON: Q. Well, if...

MR. TABOREK: A. So I think the easiest thing, looking at this, is just change that 1,000 to 400, and it will read smoothly and continuously. Maybe

that is a slip of the author, a typo, I'm not sure what.

Q. Just so I understand then, the full industrial appeal, while it is called an appeal, is in effect, an outage.

A. Yes. The term a full industrial appeal amounts to a blackout with notice is the phrase used.

Q. So it is an outage, and, as such, it is therefore not an emergency measure.

A. Correct, yes. That is the flow of this argument here.

MR. SNELSON: A. It is not an emergency measure with little cost.

MR. TABOREK: A. With no cost.

Q. We are going to get into some figures a little later on about the cost of outages. One of the figures that you are certainly aware of, and the Board will become aware of as we go through this, is a figure of $5.91 as an outage cost, if you will.

Does that outage cost apply to this particular outage that we are talking about, which is the full industrial appeal?

A. Yes.

Q. Well, could we leave this in this

fashion? As I understand it, what you are saying is the figure of 1,000 on page 105 should be 400.

A. Yes.

Q. Could you check with the author of that figure to determine if, in fact, that is a typo, as you thought, or whether he or she had some rationale or she had some rationale for that 1,000 megawatt figure, and there is some explanation for that correlation or the noncorrelation to that?

A. I can answer you right now, the 1,000 -- let's see, 103, 105; 104 is missing. Okay, yes, I will do that. I will check through what is on 104 and get back to you.

Q. Thank you.

I understand that both voltage reductions and public appeals are included in the calculation of system minutes? That is correct?

A. Yes.

Q. The demand reductions through public appeals and voltage reductions are assumed to have no cost?

A. Yes.

Q. That is contrasted with rotating outages, which do have a cost?

A. Yes.

Q. Now were these two emergency actions, that is the appeals and the voltage reductions, in fact modelled as having no cost when you were setting the target reserve margin?

A. Yes.

Q. That was in Exhibit 87, which is the '91 reliability review. Does the same answer apply for the earlier reliability analysis you were doing with respect to the DSP?

A. There were -- oh...

MR. SNELSON: A. The answer with respect to what is costed is the same, I believe. That rotating load cuts are costed and voltage reductions and public appeals have no costs attributed to them.

In the 1981 report, as to what was counted in the system minutes that were reported, then the rotating load cuts and the public appeals were counted. There were also some differences in the modelling of operating reserve and hydraulic, where they fit into the order in which things are done. So there are a number of differences in the way in which things are counted. But the same things were costed.

Q. It has been consistent throughout?

A. I believe so.

Q. Were you going to add something, Mr.

Taborek?

MR. TABOREK: A. No. I think what I was going to add is that the work done in the early stages of DSP used the 25 system minutes, which was the 1981 work, and that sort of ties in with what Ken has said.

Q. Panel, if you could turn back to page 11 of Exhibit 137, which is Table 2 from the 1981 reliability review, and I'm going to focus on appeals for these series of questions.

One very quick question of clarification before we start. In my copy, and the copy that my client received, we had great difficulty in reading the value of rotating load cuts under unsupplied energy in average with uncertainty.

A. I think that is just meant to be a star rather than a numeral. I will just check with my copy to see if...

MR. SNELSON: A. It has to be a star.

MR. TABOREK: A. Yes, it is a star rather than a numeral.

Q. That means it is very...

A. The value is very small.

Q. I notice in the table, there are other values which are less than one.

A. Yes.

Q. So, when you say small?

A. It is much less than -- near zero. What it is indicating is that -- the model is interestingly pointing out that, with the kinds of values the public puts on customer damage cost, they will tolerate only very small amounts of load cuts, and that most of the system minutes that we can acceptably put into our calculation is in effect system minutes of unsupplied energy with no cost, i.e., the appeals.

Q. This table, and as you pointed out yesterday, this is an '81 table done on '81 data, this table shows a much larger quantity for unsupplied energy due to appeals versus unsupplied energy due to rotating load cuts.

A. Yes.

Q. Now that is in 1981, using the '81 data. Now talking about today, and in fairness to you, you have indicated that appeals are reduced from ten per cent to two per cent. But even taking both those factors into account, don't we have a situation where appeals -- don't we have a situation where the unserved energy from appeals is still very much larger than the unserved energy from outages?

...

[12:05 p.m.] A. From load cuts, yes. And in effect, if you are looking at that same column and you were doing it now, you may have something about one or so. If you were recording the results of the latest calculations that we have reported in Exhibit 86 in a tabular form such as this --

Q. You said 86?

A. Eighty-seven, I am sorry, 87, the star would become a small number like one or two and the 15 to 35 range would become become a number -- oh, so that the total was around 10.

Q. So, about an order of magnitude, ten to one?

A. What is the order of magnitude now?

Q. The difference between the two.

A. Well, you are asking about public appeals and I was saying the 15 to 35 would now be something a little less than 10.

Q. Yes. And the rotating load cuts would be about one?

A. Yes, compared to being near negligible to being roughly one or two.

Q. So, there is about an order of magnitude difference between the rotating load cuts and the appeals?

A. Yes.

Q. Now, why didn't Hydro include the cost to customers of appeals?

A. Because the assumption was that there was no cost to customers of appeals. Another way of saying it is that it is so small as to be negligible.

Q. Okay. Why did you assume --

A. That, in effect, determines the percentage that you believe you can get because it is at little or no cost.

Q. Well, that is your assumption that it is at little or no cost?

A. Correct.

Q. Now, where does that assumption come from?

MR. SNELSON: A. It was a judgment and it was based on the view that if you made appeals, then most of the uses that will be cut back as a result of appeals are quite discretionary things. So, perhaps somebody will be a little bit more careful about going around their house because there is an appeal on the radio and turn off the light in the room they are not using. They probably won't turn off the light in the room they are using.

MR. TABOREK: A. And the two per cent

number that we use now, for instance, is a result of having made some appeals and attempting to measure the difference that the appeals made, and this is a difficult assessment to make because it is difficult to keep all things equal. But there was a judgment that we got about one per cent in a public appeal as a reasonable number. It is probably a bit high, but a workable number. And the logic was that when people do cut back in that instance, there is little cost associated with it.

And then, as you have said, the similar limited industrial would give a similar. So that was the chain of logic that lead us to the two per cent at no cost. Little cost, I think, is better to say.

Q. No cost, not little?

A. Little cost, I think, is -- little or no cost.

MR. SNELSON: A. No cost is modelled.

MR. TABOREK: A. Yes.

MR. SNELSON: A. The judgment is little cost.

Q. We will be dealing later, in a few minutes, with the surveys that were conducted with respect to to determining the customer outage cost which amount to, I believe it was, the 5.91 figure that

I talked about earlier.

Were any surveys or any other types of analysis done with respect to the cost to customers of appeals, or is this just a pure judgment as you have indicated?

MR. TABOREK: A. I have described to you what happened.

Q. No surveys?

A. No surveys.

Q. Okay. I understand that other utilities have estimated the cost to customers of demand reductions in response to appeals.

Has Hydro made any such estimates?

A. Not that I am aware of.

Q. Mr. Snelson, you have mentioned that while its model is zero, the word you used was "little."

MR. SNELSON: A. The judgment is that it is little or low cost. We don't know what the cost is and we model zero.

Q. Okay. Have you estimated the impact on the target reserve margin of including costs from appeals?

MR. TABOREK: A. Some assistance perhaps, not in the way that you have described it, but

something that will assist you in that regard is that in Exhibit 87, the sensitivity of doubling or having the customer damage cost of $5.91 -- call it $6.00 -- it doesn't deserve to be that precise -- was looked at and the percentages, if I can find them -- excuse me for a second.

Q. That is page 96 of the reliability review.

A. Yes. And what I am proposing is that while there is more in the way of public appeals than there is in the unsupplied energy in public appeals than there is in rotating load cuts, if you allocated some lower rate, such that it ends up doubling your total or halving your total, you can then use these charts to get a feeling for what it would be.

And roughly, you will notice -- the comparisons to make is if you take the first line, say the monthly storage Hydro line, you -- oh, and be sure to use the corrected value of figure 5.1, which I am not. There was an errata filed on figure 5.1.

So that the first line, "monthly Hydro storage" --

Q. Mr. Taborek, could I just interrupt? You are now on page 97, Table 5.1?

A. Yes. And I think the material you

handed out did not have the errata in it, so maybe I should correct that.

THE CHAIRMAN: I have it here. I don't know whether anybody else has it.

MR. TABOREK: A new Table 5 .1?

THE CHAIRMAN: The new Table 5.1, yes.

MR. TABOREK: And the first line, "Monthly Hydro Storage" should be 20 to 22 per cent?

THE CHAIRMAN: Yes.

MR. TABOREK: Okay. Good.

Then what you would do is you would compare that line with the second last line, and it would say that if your customer damage costs were halved for whatever reason, you would reduce the reserve margin that gave you minimum total customer costs by somewhere from one to two per cent; and then comparing the first line with the last line.

If you were to double the customer damage cost, you would raise your reserve margin from minimum total customer cost by about one per cent, so you could get a feeling for that.

MR. WATSON: Q. If we could turn back to Table 2. Again, that is page 11 of Exhibit 137. We have been talking about appeals. I would like to turn now to voltage reductions.

And you will notice under the frequency and duration columns, there are values given for voltage reduction; and those values are larger than the values for public appeals and for rotating load cuts.

No value is given for voltage reduction in the unsupplied energy column; however, would it be fair to say that, if numbers were supplied, they would be larger than the appeal numbers in the same way that the frequency and duration numbers are larger?

MR. TABOREK: A. I think the answer is yes. And there may be a way to -- if you look at figure 2.3 of the 1981 reliability report, which is Exhibit 140, and the figures at the back of the report -- oh, I am sorry, that is giving frequency; it is not giving unsupplied energy with respect to that. No, I am sorry, I am misleading you.

Let me rest with a "yes." I thought I might be able to give you some numerical development of it, but I can't.

Q. Okay. So, it would be bigger.

Earlier when you were talking about the difference between appeals and load cuts, we were talking roughly an order of magnitude from one for the rotating load cuts up to around ten for the appeals. Voltage reduction is going to be larger.

Is an order of magnitude larger again?

MR. SNELSON: A. I think we need a caution here, and that is that these load cuts are actions in Table 2 are shown in a specific order. The assumption in coming to this table was that as you get progressively into trouble, you would cut managed loads, which is on the top of the table, which in our current terminology is load shifting. That is move loads.

You would then cut interruptible loads. You would then call upon the interconnections for emergency assistance. You then reduce voltage and so on down the table in that order.

THE CHAIRMAN: What does the next one stand for? I can't read it.

MR. SNELSON: BHWP.

THE CHAIRMAN: What is that?

MR. SNELSON: Bruce Heavy Water Plant. And that action is the cutting of the electrical load to our own heavy water plant, which we treat as something like an interruptible load. We would stop making heavy water in a capacity emergency. This particular order of actions has a certain degree of uncertainty to it.

And Mr. Barrie on my right would explain

from an operating perspective that the order in which these actions take place is not necessarily the order which is shown here. For instance, it may be that public appeals would be made in anticipation of a problem which may or may not occur. And that the need for voltage reductions might be held in reserve as something to do at a later time when the problem occurs. Now, if the problem doesn't actually occur, you have made the public appeals first.

And so, the ratios of these numbers does depend upon the order in which these actions are taken. Clearly, all of the actions will be taken before we start to cut firm load. Cutting firm load is the last thing that happens. But the order in which these emergency measures take place -- for convenience of modelling, we have to assume an order, but in reality, the order may be different, and that would affect the ratios between these various quantities.

But the principle you are driving towards is correct, that the unsupplied energy from voltage reductions will be considerably higher than that associated with firm load cuts for a reasonably reliable system.

A system that is designed to be reasonably reliable will have a larger proportion of

unsupplied energy associated with public appeals and with voltage reductions than with rotating load cuts because if you have achieved a reliable system, you have very small limited rotating load cuts.

MR. WATSON: Q. It is going to be larger --

THE CHAIRMAN: I don't think you still got the answer to the question you asked.

MR. WATSON: The question was--

THE CHAIRMAN: Which was, what is the --

MR. WATSON: Q. --is it going to be an order of magnitude larger in the same way that the first two differ by an order of magnitude? Is that a fair estimate or is there another estimate which would be a little closer?

MR. TABOREK: A. An order of magnitude larger than the star -- oh, than the appeals?

Q. Yes.

MR. SNELSON: A. No, I would estimate it to be of the same order of the appeals, but when I say an order of magnitude, I am thinking of a factor of ten.

...

[12:20 p.m.] Q. That's what I am talking about.

A. There are different interpretations of what is an order of magnitude.

Q. Okay, perhaps I should clear that up then. My definition of an order of magnitude is a factor of 10. That's why I indicated that there was an order of magnitude difference between rotating load cuts at one and appeals at 10.

A. Yes.

Q. So, you are saying it would not be an order of magnitude using that definition up to voltage reductions but it is some larger value. Twice as large?

A. You could use the model to estimate the size of the unsupplied energy, but I am not sure that I would attribute very much significance to the results, because the result depends upon the order in which these emergency measures are undertaken and any order that you put into the model is to some degree arbitrary. It depends on the characteristics of the particular situation, how quickly the problem develops, how much of it is foreseen by the operators and what actions they take to reduce it.

So, that it is larger than rotating load cuts is plain, not that far different perhaps from

public appeals but we don't really have a good estimate.

MR. BARRIE: A. I wonder if it would help if you looked at an actual year where this actually occurred. It may not be exactly relevant to the future 20 years, but it certainly gives an indication of orders of magnitude at least.

We don't do these very often, first of all, so you have to pick 1989, probably, when we did have voluntary curtailment, or public appeals, if you will, and we had voltage reductions. It's actually in, reported in Exhibit 138.

THE CHAIRMAN: Am I right, you once described it as a bad year; is that right?

MR. BARRIE: Bad year.

Would that be beneficial, to look at an actual year? It's the only year we have where we can make this comparison.

MR. WATSON: Q. It's the only year you have and it's a bad year?

MR. BARRIE: A. Well, when it's not a bad year, we don't do this.

Q. Could you just tell us the figure?

A. I can quickly tell you the figure. In 1989 voltage reductions were carried out and they

resulted in 89.3 system minutes. The same year, and almost over the same periods, public appeals resulted in 20.5 system minutes. That's from Exhibit 138, the 1989 performance reliability report. I should add that what was --

THE CHAIRMAN: What about load cuts?

MR. BARRIE: Zero load cuts.

THE CHAIRMAN: Zero. Did the public appeals include industrial appeals?

MR. BARRIE: Limited industrial appeal, as Mr. Taborek --

THE CHAIRMAN: Included limited industrial appeals?

MR. BARRIE: Yes, sir.

But I think I should emphasize, that is always an estimate. We do not do trials for public appeals. So what we have to do is we have to look at the demand curve after the fact and estimate what it would have been had there not been a public appeal. So as such, there is an element of a good deal of judgment.

In the case of voltage reductions, it's the same, except in that case we do do tests. We do tests twice a year, so we have a better feel. We feel for comfortable about the estimate we gave for voltage

reductions than we do for public appeals.

MR. WATSON: Q. And your estimate for voltage reduction is that it is larger than public appeals?

MR. BARRIE: A. Yes, it was approximately -- well, it was 89 compared to 20.

Q. Well, in fairness to you, you said that was a bad year. In a good year you are still going to have your voltage reduction larger than your public appeal, are you not?

MR. TABOREK: A. In a good year, you can have either.

MR. BARRIE: A. You can have either.

I should refer you to the diagram. If you want to pull it out, figure 2.14 in Exhibit 138, and it is very, very evident we had -- well, I can just read the numbers off. We had 89, as I said, in 1989; we had three in 1988 and one in 1985, and none in all the other years. So I am giving you the year that we have some data to give you.

Q. Sure.

MR. TABOREK: A. One of the things that I think is happening here is when we talk reliability, we tend to talk about averages and expectations, which are, in effect, averages over a period of time, and

what they tend to do is to mask the reality. Generation planning is a game of odds.

Q. Sorry?

A. It is a good of odds, probabilities. You do not get the average amount of outages in every year. The way it's set up, that you will go on for many, many years with no problems, and then you will get a year with problems, '89. And when add that big problem year in with a bunch of no problems years you, in effect, get an average.

I have a rather morbid analogy. It's like Russian roulette. The fact that some people click on an empty chamber is not an indication that this is something that it's wise to do. What you are very much concerned about is that one bad year, if you will.

The reliability game is like this, and the interesting thing about it is you can do some very foolish things on the generation reliability side and you can be lucky and you have no problems. Now, the obverse, you can do some very clever things and you can be unlucky and you can have problems.

It's because generation reliability is like that that we do these expectations and we look very much at the case of, how close are we to this problem area? You don't want to position yourself

right on it because the nearest variation is going to put you into a really serious problem. And so that's one of the difficulties in dealing with averages and numbers.

MR. SNELSON: A. That is why Table 2--

MR. TABOREK: A. Was done.

MR. SNELSON: A. --of the 1981 report, which was page 11, I believe, of your Exhibit 137, that's why page 2 was structured the way it is. And you notice that each estimate has three columns, an average width uncertainty which is the mathematical expectation of taking all the possible outcomes and weighting them by their probabilities to give an expected value; an average with no uncertainty which is the most likely thing that's going to happen, and the bad year which was chosen to be about a worst case in 10 chances, that is the way it was defined.

Basically, most of the average width uncertainty comes from the something similar to the bad year, the worst in 10 years. So, it's a few bad years that drive reliability, as Mr. Taborek says. And we particularly structured this table to show that it was the bad year that was the main driver and that that's really the problem that we are addressing, how do you stay away from these bad years once in a while.

We may have been lucky in 1989 in that we had one bad year. There is a tendency, once you get into a problem with generation planning, for it to take you a while to get out of your problem. And so bad years can actually cluster together. If there is a one-in-ten chance of their being a bad year, then if you were in a bad year this year, there is a much higher than one-in-ten chance that you will be in a bad year next year, because if the answer, say, is to build new generation, that's going to take four years, perhaps longer.

Q. Panel, if you could turn to page 30A of Exhibit 137, which is Table 6.4 of Exhibit 87.

THE CHAIRMAN: I'm sorry?

MR. WATSON: That's page 30A of Exhibit 137. It's page 104 of Exhibit 87.

THE CHAIRMAN: Thank you.

MR. WATSON: Q. I am still dealing with voltage reduction. Table 6.4 shows a sample of problems reported with voltage reduction in the year 1989. And, Panel, as you go down that table you will see that there are six items. It lists some of the difficulties that occurred as a result of voltage reduction and it actually refers to equipment damage that resulted. So we are dealing here not only with

inconvenience but actual customer damage as a result of voltage regulation; is that not correct?

MR. TABOREK: A. Yes.

Q. As actual damage is ocurring, has Hydro estimated the cost to customers of these voltage reductions?

A. No.

MR. SNELSON: A. I think the point here is that the 3 per cent voltage cut is done from time to time.

THE CHAIRMAN: Just a moment. I think the question was, have they estimated the cost? Wasn't that the question?

MR. WATSON: Yes. In fairness, they answered that question, they said they had not.

THE CHAIRMAN: They had not. I'm sorry, I missed that.

MR. SNELSON: But there is a response to the equipment damage, and that is that, if you note, that the areas where damage is known to have occurred are excluded from future voltage reduction tests.

MR. TABOREK: And I would like to elaborate on the word "estimate," because I am sensing when you speak to me, you are looking for a study that's in a book that has computer programs run and

this kind of thing, and no, we have not done that.

What you are seeing here, when we do a review like this, one of the things we do is call into question all of our assumptions, and our assumptions usually are never absolutely true in every conceivable case. They are the most appropriate for the circumstance to be able to model it. Now, this list of cuts is actually an extract of a shorter list that I felt was a bit too long to put in the report.

If you look at these, while there is some damage occurring, that it is on a relatively small block of megawatts. And, as Ken pointed out, we are basically reacting to that by not affecting the voltage reductions in those areas.

And having said that, so that in the case of the review, we are, in effect, pointing out that these voltage reductions are not totally with no cost, but even having noted this, that it is still appropriate to attribute to the voltage reductions in this little or no cost.

MR. WATSON: Q. I would like to follow up on what you and Mr. Snelson were saying about future voltage reductions. If I understand it correctly, you are saying that through your past experience you find out where the difficulties were, where the damage

occurred, and you exempt those areas in the future; is that fair?

MR. BARRIE: A. As operations we will exempt them from any further 3 per cent voltage. I presume you do.

Q. And I was looking at this table, I notice the very first item is on December 14th, the North Bay Hospital was unable to use their X-ray machine due to voltage cuts and as a result they were exempted.

I don't know very much about X-ray machines, but if North Bay Hospital couldn't use their X-ray machine, would this mean that perhaps other X-ray machines could be affected? And if in fact that's the situation, doesn't an exemption really not make sense in that sort of area?

MR. TABOREK: A. Well, you have made a hypothesis that we cannot verify, and if you make that hypothesis, you can go to your answer, but we can't say one way or the other.

MR. BARRIE: A. Let me answer, in general.

The voltages all over the province. So when we reduce by 3 per cent in a particular place, it doesn't mean that the absolute voltage at that point

will be the same if you did the same thing somewhere else. So, the voltage in Toronto will be different to the voltage in North Bay when we carry out a 3 per cent voltage reduction.

MR. SNELSON: A. It also varies where you are on a particular feeder from a transformer station. If you are the last customer on the feeder without a voltage reduction, your voltage may be at the lower end of the acceptable band, and a 3 per cent voltage reduction may now bring you to an acceptable level of voltage for your particular equipment.

If you are near the sending end of the feeder where your voltage is likely to be towards the high end of acceptable band before the voltage reduction, then the voltage reduction may just bring it down into the middle of the acceptable band. So, there is a wide rage of possible effects that can take place here.

Q. As you say, there are a wide range of possible effects that could take place and some of those could amount to further complaints such as the ones that are illustrated here. Everything ranging from equipment that can't be used, to actual damage that could occur.

...

[12:35 p.m.] A. I would presume that a hospital that was unable to use its equipment because of low voltage during one of our either low voltage tests or actual low voltage circumstances, would let us know they were having an unacceptable electricity supply.

Q. So, the essence of this is you do not include the cost to customers of voltage reductions, you do not have an estimate of what those costs would be, in any event.

When we were talking about appeals earlier, Mr. Snelson, you said that while the model is zero, there is some little value associated with them.

A. Clearly, to say that they are zero, value zero cost is probably not correct. But we have no means of estimating, and we expect it to be small.

Q. And, Mr. Taborek, if I could just wrap this up by saying, in order to determine the effect on the reserve margin, you'd go back to page 96, where you are talking about the effect of a higher or a lower customer damage cost, and that sentence, where you said:

> "Doubling the customer damage costs would increase the optimum target reserve by about one per cent. Having the customer damage cost would reduce the

target reserve by about two per cent."

That is the...

MR. TABOREK: A. I think that would be a good first cut, yes.

Q. Thank you. If you could look at page 29 of Exhibit 137.

THE CHAIRMAN: This is all from 87, is it?

MR. WATSON: Yes, that is Table 4.10 from Exhibit 87. It is titled "Key Assumptions in Analysis Using F&D Model."

Q. If I could refer you to assumption No. 7, "Duration of Rotating Load Cuts," and you have an assumption of one hour. Where does that assumption come from?

MR. BARRIE: A. When putting our plans together of how we will handle a deficiency, we put together a schedule of rotating load cuts. Now we can vary this to whatever we deem to be appropriate.

We use this one hour to mean that we will disconnect the customer for one hour, we will restore him and take someone else off. So, that is the one hour reference. It could be changed to something else. This is what is used.

Q. And that assumption is represented,

that one hour assumption is represented in the F&D model?

A. Yes.

MR. TABOREK: A. Let's see. No, it is not in the F&D model?

MR. SNELSON: A. The way it works is that the frequency and duration that are reported in the F&D model are the frequency and duration of an incident on the system.

So, for instance, there may be a system duration of a problem of three hours. The assumption is that operations will respond to that by three separate one-hour load cuts to different blocks of customers. Where it affects the calculation is that the estimate of the cost of unserved energy, of the interruption cost, depends upon the duration of the interruption.

So, we have selected to use the cost of interruptions that relates to a one-hour interruption, on the assumption that however many one-hour interruptions are necessary to reduce the problem on the system will be made, and will be made to different categories of customers, different groups of customers in some sort of rotational order.

MR. TABOREK: A. If you were to reduce

that duration to about 15 minutes, for instance, you would approximately double the $6 per kilowatthour to $10 or $12 per kilowatthour.

Q. So, if you reduce the time assumption by a factor of four, that results in a doubling of the customer cost?

A. Yes.

Q. Is that a linear relationship?

MR. SNELSON: A. No, the relationship, as it was estimated at the time of the system expansion program reassessment studies, which is a SEPRA for short, and I was looking for it in the 1981 report, and I don't see the figure. I believe, or it may be there, but either in that report or in the SEPRA studies that back it up, which have also been given in answer to interrogatories, there is actually a plot of the interruption cost as a function of duration.

The SEPRA studies were given in response to Interrogatory 2.7.80, and that is a very large amount of material. I think you will find it in the interim report on reliability. I can't tell you the number of that. It may be the fifth interim report, but that is about -- I can't recall numbers that far back.

Q. How does the F&D model account for

the need to maintain operating reserves?

A. The assumption is that by the time we actually get to cutting firm load, we will have allowed the operating reserve to go to zero. That is an extreme measure which our operations colleagues try very hard to avoid. But the assumption is that by the time you are into rotating load cuts, then the operating reserve has gone to zero and you are living strictly hand-to-mouth.

MR. BARRIE: A. In actual fact, that is very close to what would happen. Our assumption is that we would go down to just sufficient reserve to be able to regulate the tie lines within some band, which amounts to something like 70 to 100 megawatts, so it is almost zero.

Q. 70 to 100 megawatts?

A. Something like that, yes.

Q. So that is below your synchronized reserve margin of 240 megawatts?

A. Yes. This is in this extreme circumstance, where we have exhausted every other measure at our disposal.

Q. So, in effect, what you are talking about is, your threshold is 70 to 100 megawatts, you are less that one per cent.

A. Yes.

Q. If I could take you back to what Mr. Taborek was saying a little earlier, about walking on the edge of the cliff...

A. We are pretty close to the edge there.

MR. TABOREK: A. This is.

MR. SNELSON: A. But rotating load cuts, in our view, is over the edge; something we try to avoid.

Q. Just so I understand, what we are talking about here is the threshold for outages, is that correct? Is there a different threshold for emergency actions?

A. This is the very last thing we will do before we interrupt customers. We have done everything else that was on that list. We have appealed for help, emergency help from our neighbors, we have had public appeals, we have voltage reductions, we have done all of those things, then we will cut into our operating reserve and only then. Because the last thing we want to do is interrupt customers.

Q. And when do you start the emergency actions, at what operating margin?

A. Now, what my colleagues defined as

emergency actions in the planning horizon would not necessarily -- I would maybe not define them as such. So, I will have to define what I call emergency actions.

If I negotiate extra interconnection assistance over and above the 700 megawatts that they assume, I would not regard that as emergency. That is normal operating practice.

Q. Why don't you define what you would look at as emergency actions, and where your threshold would be. If either Mr. Snelson or Mr. Taborek have anything different to add, I'm sure they will.

A. I think a simple way to put it would be in that report that I just quoted, the PS&E reliability report, if unsupplied energy is being caused by the action, that would be an emergency action. So, I would call voltage reductions, public appeals, that is the kind of thing I would refer to as an emergency action.

Q. What is your threshold for that?

A. I'm not sure I understand what you mean when you say...

Q. Where do you start that?

A. Where do we start that? When we start cut -- if, without doing that, we were to cut

into operating reserve, we would do that. We would issue a public appeal, we would do voltage reductions.

Q. Where do those actions occur in respect to the 240 megawatt synchronized reserve requirement?

A. We would do those actions before we cut into the synchronized reserve.

Q. So that would be above that margin?

A. Yes.

Q. And then you would cut into your reserve margin, and then you are down to that 70 to 100 megawatt level that you were discussing earlier?

A. Yes.

Q. Mr. Snelson, Mr. Taborek, do you have anything to add to that from your planning perspective, as opposed to Mr. Barrie's operating perspective?

A. This is the sort of order in which, as I was discussing earlier, the order does not necessarily occur in the order in which it is shown in table 2 of -- which is on page 11 of Exhibit 137.

And it is because of the ways in which these things can arise, and while Mr. Barrie has given specific order in which would he do things, in point of fact, those are the -- that is the sort of order he would do things in, if he had time to do them in that

order. And due to the dynamics of the situation, these things can take place in a variety of orders.

MR. BARRIE: A. Perhaps I should add as well, I perhaps gave the impression that you would do them one, two, three, four, five. If you knew you were in a certain situation, you might do half of all of them immediately.

I gave a sequence which -- I was trying to imply the kind of priorities we have. But there is nothing to stop the operator doing a number of them simultaneously, or a part of a number of them simultaneously.

MR. SNELSON: A. And just to give you an idea, I think he mentioned this, but public appeals take some time to be effective. So if you expect to have a problem say at 5:00 in the evening peak, you would have to make a public appeal probably before noon to be effective.

If you invited that time to be reckoning on reducing the voltage at the time of peak, but if the peak load doesn't actually materialize or some additional generation becomes available, then you would do the voltage -- the public appeal, but not the voltage reduction. There are a variety of circumstances and there are almost as many ways this

can happen as you can conceive of.

Q. So in reality, we can be quite close to the edge, as you were saying.

With respect to the F&D model. What threshold is used there? Are we on the edge of the F&D model, or is there a threshold built in?

A. The F&D model--

Q. Before--

A. --assumes that rotating load cuts will occur when there is insufficient capacity to meet the load after having taken all those measures, including allowing the reserve margin to go to zero.

So, there is a discrepancy here between the F&D model and the operating practice of the order of the 70 to 100 megawatts that Mr. Barrie has described.

...

[12:50 p.m.] Q. Isn't it then fair to say that the F&D model might underestimate the unsupplied energy that will result from those rotating outages?

A. Yes. And I think it is fair to say that if you would just mechanically carry this through into an estimate of optimum reserve, it would show that you would need of the order of 70 or 100 megawatts of additional reserve, which is of the order of 1/2 a per cent.

And I think there are many, many sources in this calculation of uncertainties of the order of 1/2 a per cent or larger.

Q. You would take care of this through a judgment factor, if you will, then?

A. It is part of our judgment, yes.

Q. Thank you.

Mr. Snelson, you were helping us out with the outages and their threshold in the F&D model. What about the thresholds for the appeals and the voltage reductions in the F&D model?

A. I am not familiar with the current order that they have in the model.

Q. Could you get that for us?

A. I believe we could get that.

MR. TABOREK: A. Yes.

Q. Thank you.

I would like to turn briefly to page 30 of Exhibit 137, which is page 103 of Exhibit 87 and continuing over to page 104 of Exhibit 87.

At the bottom of that page, there is a heading, "Cutting Interruptible Loads." And here in the last line, you express the concern that actually interrupting them - that is the interruptible loads - to this limit would cause many of them to shift to being firm customers.

Has Hydro considered any modifications of the interruptible load programs to improve the long-term reliability and availability of their demand impact.

MR. SNELSON: A. Yes.

Q. Can you expand upon that?

A. Well, I think I did mention yesterday or early this morning that the terms and conditions for discount demand service were given in Interrogatory 2.6.32.

And what was previously called CIL, for capacity interruptible load, is in the process of being changed to a new category of load called "discount demand service," which has the intention of achieving the same objective. And the terms for the customer

have been made to be more favorable, to encourage them to remain interruptible customers even during periods of significant interruption.

There are two changes, primarily, that have been made: One is that the number of hours that they can be interrupted - their contractual limit on the number of hours that they can be interrupted has been reduced; and the other is that the form of compensation they get for being interruptible customers has been changed.

Previously, the way they were compensated was by a discount on their demand part of their electricity bill, and they received that discount month in, month out, whether or not they were disconnected. And during periods of good reliability, this was a real bargain; you got a discount and you didn't get disconnected.

With that set of conditions, then the customers who have perhaps been accustomed to the discount but not been disconnected, some of them got a little upset when we started to have significant disconnections, even though those disconnections were within the contractual terms that they had agreed to.

And so, the discount is now given in two ways: A smaller discount, I believe, on their demand

charge, plus they are given an amount for each kilowatthour of demand that is interrupted, which is given only at the time they are interrupted, and I believe that amount is 10 cents a kilowatthour.

MR. TABOREK: A. Yes.

MR. SNELSON: A. So this substantial amount is in excess of what they would pay for of the rate for electricity. And this has two effects: One, it encourages the customers to remain interruptible during the times when they need to be interrupted when we really need them.

And the second effect is that it actually gives our operators some incentive to look for other sources of electricity that will cost less than 10 cents a kilowatthour to avoid interrupting them.

I think a fuller discussion of discount demand service would probably be better given by Panel 4; it is a demand management option.

Q. I just had two brief questions. You were mentioning some of the terms that make the contracts more favorable to the customer in the context of DDS.

Have you looked at any terms, such as specifying a minimum number of interruptions each year, which would have the purpose say of screening out

participants who only want the discount but don't want the inconvenience?

MR. TABOREK: A. You mean give it to them whether it has to be done or not - they are going to be interrupted regardless?

MR. BARRIE: A. It is not our policy, no.

MR. TABOREK: A. Is that what you meant?

MR. SNELSON: A. I don't think that would be very popular with the customers.

Q. So that hasn't been looked at all?

A. There were a variety of things that we looked at when the terms were being revamped for discount demand service. And as I say, I think Panel 4 is better qualified to discuss that. It is a demand management option. It was dealt with by our Energy Management Branch. But both operations and planning were consulted in that process.

Q. Okay. What about tying the term of the contract to the lead time of the gas turbine unit?

MR. BARRIE: A. That is done.

Q. That it is already done?

MR. SNELSON: A. We have insisted on that from planning, that a customer who wishes to take capacity interruptible load cannot divert to firm load

immediately. And I am not sure what is in the discount demand service terms, but under the previous capacity interruptible service, I believe that they had to give out a two- or three-years' notice of their return to firm load. And at the end of that period, they could become firm load, but they were in a separate category.

They were still the first firm loads that were interrupted for a remaining period to take it up to five years. So essentially, they couldn't become fully firm until five years. And that was intended to make sure that we had the time, if necessary, to add some form of generation or to contract for the purchase or whatever, to respond to their need for firm power.

MR. BARRIE: A. Could I add, that is in the demand discount service as well and it is still five years.

Q. Yes. Thank you.

One more question before we leave this section: Can the steam and electricity supplies to heavy water plants be interrupted without curtailing generation from the nuclear plants?

MR. TABOREK: A. Yes.

MR. BARRIE: A. It depends. (Laughter)

MR. SNELSON: A. I am not sure you are getting questioned the right way around. (Laughter)

Q. Ms. Ryan? (Laughter)

MS. RYAN: A. Do you want four different answers?

Q. Please go ahead.

MR. SNELSON: A. I think what you said was, can the steam demand be curtailed without interrupting electricity demand?

Q. No. My question was: Can the steam and electricity supplies to your heavy water plants be interrupted without curtailing generation from your nuclear stations?

A. And I believe the answer is yes.

MR. BARRIE: A. Yes.

MR. SNELSON: A. We had --

MR. BARRIE: A. I will take back "It depends." Yes.

Q. Okay. For how long?

MR. SNELSON: A. If you shut down heavy water production, indefinitely.

MR. TABOREK: A. The heavy water plant has an auxiliary fuel supply that can be used to continue operations, albeit imperfectly. And in practice, what happens with the heavy water plant is that the steam is basically used to maintain the system in a reasonable position for a comeback, such as to

prevent -- excuse me, the steam, the fuel, the auxiliary fuel -- such as, for instance, to prevent freezing if it were to happen in winter, for instance.

MR. SNELSON: A. We did point out in Table 2 of page 11 in Exhibit 137 that the the letters BHWP stand for Bruce Heavy Water Plant.

Q. Yes.

A. And that is the interruption of the the electrical load. And that is considered to be an interruptible load. It just happens to be an Ontario Hydro-owned interruptible load.

MS. PATTERSON: So, for how long could that be interrupted?

MR. TABOREK: As long as you were willing to accept the interruption in the production of heavy water.

MR. WATSON: Q. Well, how long is the nuclear station willing to accept that?

MR. TABOREK: A. The nuclear station will run independent. You could think of it as a factory somewhere shutting down. And the nuclear station will run happily whether that factory has its power on or off.

Q. Doesn't the nuclear station need the heavy water that is being produced?

A. Oh, that is heavy water that was produced in the years before the nuclear station came into service.

So, for instance, now the heavy water that is being made at Bruce is going to Darlington. Now, there is some makeup that goes back to the other stations, but there is an inventory. The heavy water for the Bruce plant was typically made in the ten-year period leading up to the opening of the Bruce plant.

Q. Okay. You are making heavy water today?

A. Yes.

Q. And --

A. For Darlington and for loss makeup.

Q. All right.

A. What that means is it is for Darlington, for all intents and purposes.

Q. And you mentioned that one of the things that would occur if you had lost the ability to make heavy water would be that you would rely on your inventory?

A. Yes.

Q. How long would your inventory last?

MR. SNELSON: A. For makeup?

Q. Yes.

A. Several years.

Q. Several years?

A. Yes.

MR. WATSON: Okay. Thank you. I am about to turn to another area, Mr. Chairman.

THE CHAIRMAN: We will adjourn until 2:30.

THE REGISTRAR: This hearing will adjourn until 2:30.

---Luncheon recess at 1:04 p.m.

...

---On resuming at 2:37 p.m.

THE REGISTRAR: This hearing is now in session. Please be seated.

THE CHAIRMAN: Once more this afternoon we have to stop around 4:30.

MR. WATSON: Could I have one minute, please?

MRS. FORMUSA: With Mr. Watson's permission, I have here a number of interrogatory undertakings that were given for Panel 1. I have the eight copies for the panel, copies for all the parties that participated in Panel 1 are placed in their mailbox is or sent to them.

If I might, I can give them to Mr. Lucas now and they will go into Exhibit 134. Each of them is numbered pursuant to the undertaking that was given, 134.1. They are not all here. There are about ten of them.

THE CHAIRMAN: How many more are to come, do you know?

MRS. FORMUSA: No, I don't. But there are about ten here. I will give them to Mr. Lucas.

THE CHAIRMAN: If they can be marked as you have marked them.

Thank you, Mrs. Formusa.

Mr. Watson?

MR. WATSON: Q. Panel, if you could turn to page 32 of Exhibit 137, dealing with customer interruption cost. Page 32 and the following page, 32A, deal with these costs.

THE CHAIRMAN: And they come again from Exhibit 87, do they?

MR. WATSON: They do, Mr. Chairman. That's page 81 and 82 of Exhibit 87.

THE CHAIRMAN: Thank you.

MR. WATSON: Q. Those pages mention customer surveys and those surveys were done to attempt to determine the customer interruption cost.

Could you tell us the dates of those surveys? It says between '76 and '79, is that the best information?

MR. TABOREK: A. Well, there was a series. The original Ontario Hydro series was done over that time period. And further information is in Exhibit 140, I believe, which will make it a little more precise.

Then there is also a reference to surveys done by the University of Saskatchewan and the Canadian Electrical Association. Now it says in the '80s, well, it was actually I believe '84/85, in that period, where

two of the areas in which Hydro had received some questionable results; namely, farms and residences were refined with University of Saskatchewan/CEA surveys.

Q. Mr. Taborek, you mentioned that University of Saskatchewan updated the surveys and you also mentioned the Canadian Electric Association?

A. Yes, they are the same survey but they were done -- I think the CEA commissioned the University of Saskatchewan to do the surveys.

Q. They are the same survey, though?

A. Yes, yes.

Q. And only the residential and farm sectors have been updated since 1984?

A. Yes. There is some preparatory work now in place to do new surveys, again the University of Saskatchewan with the support of electrical utilities.

Q. Is that ongoing or is or that something that will occur in the near future?

A. It is starting and it will occur in the near future.

Q. And those surveys are the basis for the information which is at a Table 4.8 on page 32A of Exhibit 137; is that correct?

A. Yes, and you will notice two instances in which the University of Saskatchewan

information was substituted for Hydro's original information.

Q. So, all of this information is from '76 to '79, save for the University of Saskatchewan, which is '84?

A. Let me just rephrase that. All of the base information, and then there are two adjustments made to bring it to the present day, one is to escalate to allow for present day costs and the other is to adjust for the present day mix of electricity use by the different types of users.

Q. But that's based on the data set?

A. Based on the data set obtained earlier, yes. I would mention, though, that in the course of our review, we looked at information obtained in our survey on other utilities, and that's reported in Exhibit '87, and we felt that this remained reasonable information to use.

Q. Why did you feel that?

A. Because, basically, it's an area - I seem to be saying this a lot - where there is a good deal of uncertainty in the information and the use of the information, and that it is still reasonable.

Q. So, you feel it's reasonable. You are conducting a survey in the near future to review

these numbers. Can you tell us when you think that survey will be completed and when the new numbers will be available. This year, for instance?

A. No, I can't, I'm sorry. I don't think it will be this year.

Q. Is this a one-, two-year project, or could it be as long as three or four?

A. I'm sorry, I don't have that information. I think you can see by that, I am not waiting breathlessly to get it.

Q. Could you find out whether in fact this is -- what sort of time frame we are looking at?

A. Yes, yes.

Q. When you conducted the original surveys, what measures did you use to ensure the reliability of the results?

MR. SNELSON: A. I doubt that Mr. Taborek can recall because he was not involved in the area at the time. I was involved in the area at the time and my recollection is a little hazy.

The survey results are documented more fully, as I said this morning, in the SEPRAS, that system expansion program reassessments study reports, and my memory was in fact correct. It is attached to Interrogatory 2.7.80, and it is the fifth interim

report that includes the reliability studies at that time.

The studies were carried out by a team from what is now our energy management branch but it would have been the forerunner organization of that because it didn't exist at that time, and they were generally recognized at the time as being the most thorough studies of customer damage costs that have been done in North America, and they were widely quoted among other utilities.

So, as to the exact specific details of how it was done, I don't think we can recall, but they were considered to be the best available at the time.

Q. Is it fair to say that you are going to attempt to do a similar high quality job this time?

A. I am not familiar with the details of what is underway at the moment. I believe it's a cooperative effort between several utilities, and whether it will end up being a check on these results or whether it will end up substituting for these results I don't know.

MR. TABOREK: A. Mr. Watson, we did express that we had some reservations about the numbers we obtained, and indeed some of the numbers we have obtained we have not used. And even when we did use

them in the 1981 report, Exhibit 140, the report purposely pointed out that these numbers should be used with care.

And so you are using words like "quality" and it would be nice to attach that to your work. Again, I would be careful with the numbers.

I think I said in my direct that many utilities in North America will not or have not used total customer cost because of concerns they have with the use of this information. We think it's useful and we use it. We recommend others use it because it adds a measure of analysis to an area that would otherwise be pure judgment and difficult to get a hold of. But having said that, it's an area in which the the analysis is in its early phases. Like, I think Hydro's work was pioneering, wasn't it, this initial work?

MR. SNELSON: A. As I understand it, it was one of the first such studies in North America. There had been some similar work in Europe that preceded it.

MR. TABOREK: A. And so this discipline, if you will, is in its infancy.

Q. Mr. Snelson, you referred us to Interrogatory 2.7.80, we will look at that, but will that interrogatory help us with the number of customers

that were surveyed, the response rate, the number of usable responses? For instance, a 90 or some other percent confidence band, will it have that level of detail?

MR. SNELSON: A. I am just scanning it at the moment, and I doubt it would have that degree of detail. I don't see it, on scanning the report.

Q. Could we get you to provide that information if it is not too difficult to find?

MR. TABOREK: A. This again may be difficult to find because it could well be buried in archives.

Q. Your track record is quite good.

THE CHAIRMAN: When was this survey done?

MR. TABOREK: 1976 to 1979.

THE CHAIRMAN: And it was done outside your organization, was it?

MR. SNELSON: It was run from within the forerunner of our energy management branch. So, there was a multi-branch task group doing the study.

The planning people, myself included, had some input to the definitions of what was going to be studied, and so on, and the interpretation of the results, but the work was run from within, as I say, the forerunner of our energy management branch. So, it

won't probably in our own files. It will be in other branch's files if they are still accessible.

MR. WATSON: Q. Again, perhaps you could let us know if you can find that information.

MR. SNELSON: A. Okay.

Q. What you might also do, if it is readily available, is give us the terms of reference of the new survey that you are proposing.

A. Yes.

MR. TABOREK: A. That is available.

Q. Thank you.

Mr. Taborek, I would like to explore, a little bit, the statement that you made earlier about the effect of higher or lower customer damage cost, and that is at page 33 of Exhibit 137. That's page 96 of Exhibit 87. And the sentence I am referring to is at the very bottom of the page:

"Doubling the customer cost would increase the optimum target reserve by about one per cent. Halving the customer damage costs would reduce the target reserve by about two per cent."

Can you describe the process by which this sensitivity analysis was conducted?

A. Yes. If you go back to Figure 5.1.

Q. And if we could just take a minute. That is on page 10 of Exhibit 137.

A. The customer damage costs will shift the slanting lines to the right if they are higher and to the left if they are lower.

...

[2:47 p.m.] Q. Didn't you do any computer runs or any sort of analysis to determine the figures that were used in those quotes?

A. In those quotes? Sorry? What do you mean?

Q. I quoted from page 96, and you are talking about the interaction between doubling customer damage costs, and the effect on the target reserve margin. You come up with figures of one per cent if you double the cost, and two per cent if you halve it. I mean, where do those figures come from?

A. The one and the two per cent, or the doubling and the halving?

A. All of them.

Q. Well, the doubling and the halving is a traditional technique you use when you wish to study the sensitivity of a parameter in which there is some uncertainty you'd like to get ahold of. It happens that the doubling approximately takes you to the cost for a 15 minute rotating load cut, so it had some relevance there. So those are the reasons for doubling and halving.

Q. And you mentioned a sensitivity. That is what I'm trying to explore.

A. Because we wanted to know the

sensitivity of the reserve margin to changes in that input number, roughly $6 a kilowatthour. So, having established what the range of inputs would be, it is merely multiplying by those different dollar numbers to get the shift in the curve.

Q. To get the either one per cent or two per cent?

A. And the curves will shift to the right for the higher, and they will shift to the right about one per cent, and they will shift to the left about two per cent.

Q. So you didn't have to do any additional F&D model runs to deal with this?

A. No, because the unsupplied energy is the same in these runs. It is the cost to the customer of that given unsupplied energy. So, it is a very quick and easy thing to do.

Q. So, in effect, what we are saying here is that the target reserve margin is just not very sensitive to outage cost assumptions?

A. That is correct. If, and the big "if" is if you are working with a reserve margin that takes you near minimum total customer cost, because as we have said a number of times, and you have seen in various figures, that at the minimum total customer

cost, there is very little rotating load cuts. And since there is very little, you can multiply it by what you will, and you are not going to change things very much.

And that is also one of the reasons why, while we feel that there is a great deal of uncertainty in these numbers, when they are being used in this fashion, you can still tolerate that uncertainty and come to a reasonable conclusion, because of the nature of the relative size of the numbers. And that was why, I said - perhaps, too flippantly - that while we were looking forward to getting the information from the new survey, it wasn't a critical thing to us to get it, because of just this underlying fact.

Q. In effect, the insensitivity, to put it in terms of figure 5.1, occurs because the slope of the curves is very steep at the cross-over point, isn't that correct?

A. Yes. And it steepens -- well, no, I think maybe that was too quick an answer. It is because the amount of unsupplied energy in rotating load cuts at minimum total customer cost is quite small. If you recall, when we were looking at Table 2, we didn't put a number on it, we put a star and said it is near zero and that our target of system minutes, 10

or 25 or whatever, is mostly uncosted assumptions about emergency measures.

So, it is the fact that your optimum comes about with little in the way of load cuts, or the customer's value load cuts to the point where you don't have to go very far to make it worthwhile to protect them from it, that means it is not significant or it is not sensitive.

Now then, if you were to cut the reserve margin to where you were giving customers a substantial number of load cuts, then you would find that your assumptions about the value customer's place on load cuts would be very critical in determining what your margins are, your optimal positions.

And the other thing I would suggest also, that if you do a survey of customers after a period in which they have had no load cuts, and then you do a survey of customers after a period in which they have had a lot of load cuts, you might get some surprises, too.

Q. So are you saying the slope of the curve is not one of the reasons for the insensitivity?

A. I think that is correct. It is not, the slope, but the small amount of system minutes that result in the near optimum position, as I understand

it.

Ken, would you...

MR. SNELSON: A. I think the shape of the curve has something to do with it. But, is as true with a lot of these reliability calculations that things change quite rapidly. If you have a system 25 per cent reserve, and you reduce the reserve level 20 per cent, then a lot of measures, such as unsupplied energy, might go up by a factor of 10 per cent. You reduce it by another five per cent, and it is now up by another factor of ten, say, a hundred; it is a kind of an exponential type of relationship to a lot of these parameters. It tends to mean quite wide variations and some of the parameters tend not to shift the reserve from our margin that is optimal a very long way.

Q. Perhaps how we could deal with this, sir, there appears to be a little bit of disagreement here.

MR. TABOREK: A. I don't think there is a disagreement. I think we are saying the same thing from slightly different directions, that is all. We are describing the elephant from the front and the back. We are still describing the elephant.

Q. Okay, I just wanted to make sure I was looking at the same elephant.

A. There is actually an illustration in figure -- in Exhibit 140, where the effect of customer damage costs of two different levels are shown, and...

Q. Where is that again, Mr. Taborek?

A. Okay, it is Exhibit 140, and figure 2.6. I suspect it will also appear in other figures, but that is a convenient one.

If I remember the chronology here, it shows a SEPRA estimate, and it shows a 1980 estimate. The SEPRA estimate was for only some of the categories, and it did not have in it the large farms, office buildings, retail, government agencies. What it had in it was residential, small industrial and large users. So, they came out in batches.

And the upshot of that is the SEPRA estimate was low, and then the next batch of estimates came in, and this included some of the very high ones, like the large farms. So, they boosted the numbers.

When you look at this curve, in the way we have been discussing, one of the things you are interested in doing is looking at the minimum for the minimum total customer cost. And what you see is that in the region of low reserve margins, in which you have high unsupplied energies, then the magnitude of the customer damage cost has a big effect. But as you move

to higher levels of reliability, and the amount of unsupplied energy that you are costing drops, the difference between the costs, the higher and the lower estimates, rapidly disappears, until in this case, at about the 26 per cent level, it disappears totally.

Ken was, I guess, discussing the slopes to the left, and the rapidity with which the customer damage costs rise and the unsupplied energy rises, as you get into trouble, this cliff that we had mentioned, and I was discussing the other end of this elephant, in the region of the optimum, in which there is very little costed unsupplied energy, and hence the unit costs are not significant.

Q. Thank you.

A. Not "significant"; it is -- the word sensitive.

Q. Sorry?

A. Sensitive is a better word than significant.

Q. Has Hydro valuated the sensitivity of the target reserve margin to the CTU cost?

A. Well, you can do it by eye on figure 5.1, in essence, by applying factors above and below. You can just scale it off just by eye. If you drop it ten per cent, raise it ten per cent, you can just scale

it off the figure. And if you want to try...

Q. Thank you. Does Hydro use customer interruption cost data for other purposes such as rate design?

MR. SNELSON: A. Other purposes, yes. I don't believe so for rate design. There is nobody on this panel who is expert in rate design.

Q. Can you tell us what those other purposes are?

A. I believe they are used in certain aspects of the design of the regional supply system and in some specialized cases. They may also be used as an operating aspect, but Mr. Barrie would be more expert on that than I.

MR. BARRIE: A. I'm not aware of them specifically being used. Maybe in the regional supply, by regional supply, we mean not the integrated system that I have been referring to.

Q. Thank you. I'd like to turn now to load forecast uncertainty. Panel, could you turn to page 34 of Exhibit 137? That is page 70 of Exhibit 87.

You will see that page 70, we have Table 4.4, which is standard deviation of historical errors, per cent of actual peak load. There is a series of lead time years from one to eight, and then two columns

of standard deviation data.

Does the standard deviation of load forecast uncertainty, which is used as an input for the F&D model, come from this table, Table 4.4?

MR. TABOREK: A. Yes. It is the No. 8.8, which occurs in the column "Standard Deviation About Sample Average," and at the row for four years.

Q. Mr. Taborek, you have referred us to the row that is at four years lead time, and the figure 8.8 is under "Standard Deviation About Sample Average." Continuing along that row, there is a figure of 9.1 under standard deviation of zero. Why is there a difference between those two values?

A. Because the mean of the sample is not at zero, or you can -- in Exhibit 87, figure 4.1...

Q. That is just after page 92?

...

[3:03 p.m.] A. Yes. It shows the actual distribution of errors and the difference between the mean of the sample and having the standard deviation taken about the zero point.

Q. Do the differences between those two columns of figures imply a systematic bias in forecasting errors, either underforecasting or overforecast?

A. In this time period, yes.

MR. SNELSON: A. I think one would have to do a statistical test to see whether that showed a statistical bias.

The fact that you have taken a random sample from a group of data which has no bias and that the sample has a mean other than zero doesn't necessarily mean that the population it is taken from has bias.

MR. TABOREK: A. I defer to Mr. Snelson's answer.

Q. Have you done that analysis, Mr. Snelson?

MR. SNELSON: A. This is the sort of question that was looked at by Mr. Burke in his assessment of ranges above forecast.

In this particular case, the deviations

between the distributions and the difference between the 8.8 and the 9.1 is really quite small.

Q. It isn't in year eight, though?

A. That's correct.

MR. TABOREK: A. That is one of the reasons that it is a very good idea to have short lead times for your reliability planning, to have your approvals in hand so that you can build quickly because otherwise, you have to plan for very long lead times and higher and more uncertain errors.

MR. SNELSON: A. Well, I think Mr. Burke's evidence has been that there was a major deviation in the 1970s and that he has done analysis on load forecast errors.

And his analysis on load forecast errors and prediction of load forecast errors is more detailed and superior to a simplistic analysis that might come from just a straight plotting of historical errors.

Q. Okay. Mr. Taborek, you had referred us to Table 4.1, the very next page -- sorry, Figure 4.1.

The very next page is Figure 4.2 and that is at page 35 of Exhibit 137. That is a graph titled, "Comparison of Models, standard error with history."

What is the model that is referred to

there?

MR. TABOREK: A. The model that is referred to is the F&D model and it is the information that had previously been in the F&D model.

And the source of that information is earlier techniques that the load forecast department had used to describe load forecast uncertainty.

And I might just make a point: You have noted that there are wide differences in the long-term. And in the point of our review, we noticed that in the four-year period in which we were forecasting with CTUs as peaking units, there was very little difference in those two approaches.

So we were pleased that we achieved that kind of a convergence in the lead times in which we were interested.

And we were also very pleased that we would not have to deal with longer lead times. It presented much more of a challenge.

Q. Panel, if you could turn to page 36 of Exhibit 137. That is page 73 of Exhibit 87. There we have Table 4.6.

And just underneath that, there is a sentence that says:

"At the four-year lead time, of

interest in this analysis, the results of
the historical analysis and that of Monte
Carlo analysis are almost identical."

Now, is the Monte Carlo analysis that is described there the same as that which is used in creating the load forecast bandwidth as described in the D/SP?

A. Not quite, but it is related to it. We mentioned two particular approaches and we are aware, of course, that Mr. Burke was working on a new approach for describing the bandwidth.

Now, the approach that he is dealing with is primarily dealing with the long-term --

Q. Excuse me, Mr. Taborek, when you said "the approach he is dealing with," is that the one that is referred to in --

A. That is he is developing and which is used in the D/SP.

Q. Thank you.

A. It deals primarily with the long-term.

And what we are looking for - and I think Mr. Burke will have told you that and I will just give you a bit of this because I am not an expert.

Mr. Burke is the best source - that when

he does his long-term forecasting, short-term variations or cycles tend to be damped out. And his route forecast is for an energy analysis, not a capacity analysis, and it is a long-term steady state trend mostly linked to population, if I may crudely simplify his approach.

In the short term of four years, it is important for us to take account of the these cycles, so we gave the results that we had from the previous page to Mr. Burke and asked him to test it against his new approach.

And he did and he developed this Monte Carlo analysis where he introduced short-term uncertainties and he advised us that at the four-year lead time, he had a number like 8.6 where we had a number like 8.8. And so, we were again pleased to see that the numbers on load forecast uncertainty were coming into the same region.

Q. If we look at Table 4.6 on the same page, we can do some quick analysis. If we look at the eight-year lead time, we can see that the Monte Carlo analysis gives us a standard deviation of 13.7 per cent of the peak.

And to get an 80 per cent confidence band, as I understand it, you take a figure of

approximately 1.4 and multiply that by your standard error; is that correct?

A. Well, I think you are taking me into an area which is Mr. Burke's specialty, and this model analysis is his, and I wouldn't really care to address it. I am not competent to address his area.

Q. Mr. Snelson, are you comfortable with dealing with confidence bands? For instance, would you be aware of the fact that to get a 95 per cent confidence band, you multiply by roughly 1.96? To get an 80 per cent confidence band, you multiply by roughly 1.4? Are you familiar with that?

MR. SNELSON: A. These are confidence limits under normal distribution, I presume.

Q. Yes.

A. And I would presume you have done your arithmetic correctly. I don't remember the points on the normal distribution.

Q. Well --

A. But they seem to be of the right order of magnitude.

Q. Okay. Perhaps we could just proceed, subject to you checking those figures.

My understanding is that those figures are the appropriate figures.

A. I think the point here is that the only numbers in that table that have been used in the analysis are the four-year lead time numbers.

Q. Okay.

MR. TABOREK: A. We are, in effect, pointing out that there is some uncertainty in the longer-term numbers, but we just note it.

Q. Well, I would like to proceed with both the eight-year and the four-year, if you don't mind, and if we get beyond your level of understanding, please let me know.

MR. SNELSON: A. Well, we can deal with it from a theoretical point of view as regards to the relationship to the load forecast bandwidth, then I don't think either Mr. Taborek or myself can usefully comment on that.

Q. Well, let's see how far we get.

If, in fact, we are talking about the eight-year lead time, an 80 per cent confidence band would be 1.4 times 13.7 per cent, which would give us roughly plus or minus 19 per cent.

And if the historical values were used, it would be 1.4 times 18.2 per cent, which would give us approximately plus or minus 26 per cent of the peak.

In other words, using those figures, an

80 per cent bandwidth would produce a median, plus or minus the 26 per cent for each limit. And again, I would very much welcome you checking those figures.

If you could turn to the next page of Exhibit 137, and that is page 37, you will see figure 3-12, which is the '88 basic load forecast bandwidth.

And if, in fact, we go through the same analysis, eight years out would be for 1996. And you can see the figures in the bandwidth are 24.2 for the low, 28.1 for the median, and 31.6 for the upper.

Taking those figures, I get a median and bandwidth of 28.1, plus or minus approximately 13 per cent.

Just doing that quick arithmetic --

THE CHAIRMAN: The formula that you have come up with, I don't recall that in Mr. Burke's evidence.

Is that where you derive that formula from that you just mentioned? What is your source of that formula?

MR. WATSON: Are you talking about--

THE CHAIRMAN: The 1.4.

MR. WATSON: --the 1.4? I believe that is reasonably standard statistical theory.

THE CHAIRMAN: Well, I don't recall it.

Mr. Burke spent a great deal of time describing how they created the bandwidth. And I may have overlooked it, but I just don't remember it being reduced to those simple terms.

MR. WATSON: Well, perhaps we could leave it with the witnesses.

If, in fact, that interpretation that I have put forward or that mathematics that I have put forward is incorrect, they could let us know.

THE CHAIRMAN: All right.

MR. WATSON: It is my understanding that that is --

MR. SNELSON: This, I think, is a Panel 1 issue.

MR. TABOREK: Yes. I would rather not discuss it at the eight years, but the four years, we will...

MR. WATSON: Well, we can do the same analysis with the four years and I was going to do that as well.

Q. And as you suggest, Mr. Taborek, if you are more comfortable with the four years, I can go through exactly the same numbers with the four years.

And doing exactly the same thing, you take the numbers for the four-year lead time in Table

4.6, and instead of the 13.7 number, you would use 8.6.

For the Monte Carlo, instead of 18.2, you would use 8.8 for the historical.

And then on Figure 3.12, going out four years, you would be into the 1992 figures.

...

[3:15 p.m.] MR. TABOREK: A. I think I have said that the technique Mr. Burke uses in developing the bandwidths are long-term, and they tend to damp out short-term perturbations. And he, in effect, developed a special approach suitable for the short term of this general technique, to use in comparing with the various estimates we had. And that the technique he developed, which is called Monte Carlo, in the four-year lead time, fit reasonably with the two other sources we had for an estimate of this number.

So, it is not appropriate to take Figure 3.12 and apply it against, though, because it was developed for different purposes. It was developed for long-term forecasting.

Q. It may have been developed for long-term forecasts. It does give values from 1989 on. And certainly, in going through the values, as I did in some detail, for the eight-year lead time, you see a significant difference between the results--

A. Yes.

Q. --between the two results of the Monte Carlo analyses.

A. Which in my understanding in discussing it was due to the fact that the short-term variations have not been included in 3.12 and hence

there is less variation, in that the short-term variations are included in Table 4.6, and that that's what accounts for that difference.

Q. Is your answer the same for the four-year lead time?

A. It's only with respect to the four-year lead time. That's the only time I am answering with respect to.

Q. Okay. And can you help us all as to why the difference would be so large or even larger in the eight-year time frame?

A. No.

Q. Mr. Snelson, can you...

MR. SNELSON: A. I can't help you.

Q. How is load forecast uncertainty represented in the F&D model? Is a discrete approximation used?

MR. TABOREK: A. No. Our most recent developments have been to, in effect, utilize various levels of load forecast uncertainty and to run the F&D model, I think it is, approximately 21 times at 21 different levels of load forecast uncertainty, and to take the results from this multiple running.

This was an essential part of being able to determine, in our way of thinking, the energy limits

on the hydraulic, it was an essential lead to that.

Q. Are all 21 of these weighted equally?

A. They are weighted according to the probability of their occurrence.

Q. A simple weighting technique, as we saw earlier?

A. Yes. It's, in effect, an expected technique in decomposing it into its components.

Q. Would you refer to page 38 of Exhibit 137, please? That's figure 15-45 from the D/SP. This curve shows the 24 per cent target reserve margin being met for all three scenarios after a transient period.

Now, as I understand it, the target reserve margin of 24 per cent assumes a certain load forecast uncertainty; is that correct?

A. Yes.

Q. I guess the difficulty I am having is that if you apply a 24 per cent target reserve margin, with its assumption of load forecast uncertainty, and apply that to, for instance, the high demand scenario, the upper band, if you will, which is at the upper end of the 80 per cent uncertainty band -- in effect, aren't you double-counting the load forecast uncertainty?

A. Well, not if you are on the high

scenario.

Q. What if you are not?

A. Then you would be applying it to the scenario in which you are on. You would adjust -- I might mention, incidentally, that for much of -- I'm sorry, I will stop there.

Q. Sorry?

A. I was going to say something that wasn't really relevant.

Q. I am not sure I understand. I was concerned about whether there was some double-counting there.

MR. SNELSON: A. I don't believe there is. The upper load growth scenario is based on the assumption that the load follows the upper bandwidth of the load forecast bandwidth. And in deciding on how we would react to that, we did not assume that we would know immediately that we were on an upper load growth scenario and thereby plan accordingly. We assume some sort of delay, and that delay was of the order of a few years. And during that period, you would suffer the uncertainty that is modelled in the F&D program.

In fact, you would probably continue to suffer that, because, even though you are on a high load growth scenario, you probably wouldn't suddenly,

in a flash of inspiration, realize that your load growth is now four per cent instead of two per cent. You are going to successively, over a period of years, gradually increase your load forecast as you build in your evolving knowledge about the new trend.

And we allowed the reserve level to slip in the upper load growth scenarios to about 20 per cent, on the assumption that either we couldn't build plant fast enough, or we wouldn't realize that we needed to build plant fast enough, and we didn't really have to decide which of those circumstances was driving it.

But we did model in that circumstance for most of the period about a 20 per cent reserve. And you will notice on that figure that, in the period before we can respond, the reserve drops below 20 per cent.

Q. You are referring to the 20 per cent figure. How did you decide on 20 per cent?

A. It was a judgment based on the overall judgment that reserve levels should be in the 20 to 24 per cent range. In the median load forecast, if things are developing as you expect, then we have a preference for leaning towards the upper end of that in terms of reserve margin, and that's in the median

forecast was prepared on 24 percentage. I think we have given a number of reasons why we prefer to be towards the upper end.

In the situation of high load growth, we would be scrambling and we would be struggling to maintain even an adequate reserve margin of 20 per cent. So, it was a judgment.

Q. So, you are saying you would be struggling, so you determined that would be your absolute minimum and you just couldn't go below that?

A. We would struggle much harder to keep the reserve above 20 per cent than we would to increase the reserve from 20 to 24.

MR. TABOREK: A. And you use the term "absolute minimum." It is more that you are getting into a region in which the risk of customer damage costs rising sharply are beginning to hit you -(coughing)- beginning to rise sharply.

Q. And that's what we were referring to the other day, Mr. Taborek, when you were talking about the slope, over on the far left-hand side of the curve the slope is a lot higher--

A. Yes.

Q. --and you are concerned about moving, a small change there will cause a large change.

A. But nevertheless, in the region of the minimum, you could make small adjustments away from the minimum and still be on a relatively shallow part of that curve. And it is only when you got off it some way that you began to rise sharply. And our judgment was that 20 per cent was a reasonable distance to the left of the curve for a brief period of time, well, brief in planning terms.

Q. Throughout most of the upper growth scenario, certainly from '94 to, say, 2004 --

A. Brief in planning terms. (Laughter)

Q. Through that brief period, you're right at the 20 per cent reserve margin?

A. Yes.

Q. You then indicate that you would go up to 24 percentage, continue along at that level throughout the balance of the planning period.

A. Yes. Although -- I'm sorry, I am prejudging your question.

Q. Please go ahead.

A. In the early part of this time period, we do not have an option to build new generation to restore the reserve margin because there is time for approvals, et cetera. And the first that the new generation could appear is -- I forget the

first dates in the upper, but they are in Plan 15, and so it's not the full 15 years in which we consciously make that decision. The period up until then, we are scrambling to put everything we have onto the system to maintain 20, but we can't use new generation to do it.

Q. Are we close to the cliff again?

A. Twenty is getting close to the cliff.

Q. Is it possible that we could go below 20?

MR. SNELSON: A. Yes.

MR. TABOREK: A. Yes. It's this point I mentioned a little earlier, the possibility you could do very clever things with reliability and hit bad luck, and you can do very foolish things with reliability and have good luck. But your chances are you will have bad luck.

Q. What you are saying in the upper scenario is that in 2005, new supplies coming on line and that brings you back up to 24 per cent?

A. Yes.

Q. So, if that new supply is delayed or does not occur, you are at 20 per cent.

A. And it will be riskier.

MR. SNELSON: A. You have options to go beyond the 20 per cent. The increase that is shown

here is the addition of base load generation resources to raise the generation. There are various gas-fired or oil-fired peaking options that can be obtained faster than that. So those are still options.

Q. The next page, page 39 of Exhibit 137, is the first page of Exhibit 87. We can see in the last paragraph, in effect, you are saying that the reserve margin varies from 22 per cent to 24 per cent in the medium scenario. Does this mean that 24 per cent is not your minimum reserve margin?

MR. TABOREK: A. That's correct. It was described as a target, and you cannot maintain it very closely. So, when it fell below 24 per cent, we would then add units, and that tended to take you in the 22 per cent range. And so it wasn't an absolute minimum.

Q. What is a minimum acceptable reserve margin? Is it 20 per cent?

A. For what purpose? I think I need a little bit of clarification about what you mean it for.

Q. For the plan being put forward, case No. 15 in the D/SP?

A. 20 to 24 per cent range.

Q. So 20?

A. Twenty is the minimum temporarily, 24 is the target, and to be in that range.

Q. If I could ask you to turn to page 40 of Exhibit 137. That's page 19 of the 1981 reliability criteria.

THE CHAIRMAN: Which is Exhibit... ?

MR. WATSON: Which is Exhibit 140.

THE CHAIRMAN: Thank you.

MR. WATSON: Q. You can see under the heading "Load Forecast Uncertainty," the last sentence in the first paragraph:

> "A change in the load forecast uncertainty of 1 per cent point changes the required reserve in the system by approximately 2 percentage points."

Could you explain that for us, please?

MR. TABOREK: A. The load forecast uncertainty is measuring for you how wrong you can be, how much error you can make in your load forecast.

...

[3:33 p.m.] And the more error, the more uncertainty that you have in your load forecast, the more reserve margin you need to keep you in a region of acceptable unsupplied energy or customer damage costs.

MR. SNELSON: A. The one per cent change in load forecast uncertainty that is referred to is a one per cent change in the standard deviation due to load forecast uncertainty. And by the sort of phenomena that you were describing to us a short while ago, if you are talking about things that have a one in ten chance or so of occurring, that is more than one standard deviation away from the median.

The result of applying it to our model at that time, and I don't expect the result to be very much different today, that the result was that a one percentage point change in the standard deviation of load forecast uncertainty, a one per cent increase resulted in about two per cent increase in optimum reserve.

Q. Just so I understand, when you say two per cent, is that two per cent of the 24, or is that an increase of two per cent on top of the 24? In other words, from 24 to 26?

A. Twenty-four to twenty-six.

Q. When the load forecast uncertainty

increases one percentage point, does that mean that-the standard deviation increases from, say, 8.8 per cent to 9.8 per cent?

A. That is correct.

MR. WATSON: One final question before the break, Mr. Chairman.

Q. Why isn't an increase in load uncertainty matched one for one by an increase in reserve margin?

MR. SNELSON: A. Because the reliability of the system is driven by things that are further than one standard deviation away from the median.

Q. Such as?

A. Well, we showed that in the '81 report that most of the problems that contributed to the average unsupplied energy were in a bad year that was a once-in-ten-year case, or something similar. It is a few events that are relatively improbable that drive the average. And these events tend to be associated with load forecast errors of more than one standard deviation.

MR. WATSON: Okay, I'm finished with that area, Mr. Chairman.

THE CHAIRMAN: Take a 15-minute break.

THE REGISTRAR: The hearing will recess

15 minutes.

---Recess at 3:36 p.m.

---On resuming at 3:56 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Please be seated.

THE CHAIRMAN: Mr. Watson?

MR. WATSON: Q. Panel, earlier you were referring to interconnection assistance. I'd like to turn to that area now, please. I understand that currently...

Panel, I'd like to turn to interconnection assistance right now. I understand that, currently, the reserve requirement on the system is reduced by about 700 megawatts to allow for emergency assistance from neighboring utilities.

MR. TABOREK: A. Yes.

Q. That is an approximation, as I understand. Is there an exact number to go along with that?

A. It is not an approximation. It is the number that we use.

Q. So that is the number you use.

A. In the peak periods.

Q. Okay. So there is no more available, or that is the maximum that is available?

A. Well, we had mentioned that something like 2,000 megawatts would be available off-peak, and perhaps even more than that, if you were not experiencing a load forecast correlated type of problem, and it was perhaps a generation type of problem. And in that case, more might be available.

Q. So when you referred, in the reliability review of '91, when you say about 700 megawatts, the word "about" shouldn't be there. It is 700 megawatts.

A. Yes, and the word "about" is meant to imply the degree of precision we would associate with that number. It is an estimate, but it is the estimate.

Q. How do you represent that in the F&D model?

A. There is a provision for purchases in the model.

Q. Is it a firm resource with perfect availability?

A. Yes.

Q. Does that number change from year to year?

A. If you wish it to. There is a provision for it to change, but we did not change it.

We used 700 in the peaks.

Q. I notice in the '81 review you use 700 as well.

A. That is correct.

Q. Has that 700 figure been constant throughout?

A. Yes.

Q. Well, does it necessarily follow that nothing has changed in that period that would allow you to change that number, or have you just not examined that?

A. No, things have clearly changed. I mentioned all kinds of things are changing all the time. The changes, however, are not significant enough for the degree of precision you can achieve. Precision and degree of accuracy you can get with these estimates are such that it is not -- we didn't feel it worthwhile to attempt to refine that number.

Q. So, the changes weren't significant then?

A. That is correct. The underlying factors are still there, namely that our load forecast errors are correlated with the load forecast errors of neighboring utilities, and that that would tend to limit the amounts that would be available to us in

those kinds of contingencies.

Q. I believe in reading somewhere, I know that there was supposed to be a review of the 700 figure conducted in 1982. Do you know if that review occurred?

A. No, I don't. I'm not aware of anything since this time.

MR. SNELSON: A. I don't know where your reference is taken from, and I'm not aware of the review being done.

Q. Yes, if you look at Exhibit 140, page 10.

MR. TABOREK: A. Oh, it said, "It is intended to."

Q. Yes.

A. I'm not aware that this was done.

Q. Sorry, that was the thrust of my question. I understood there was to be a review in 1982, and I was curious as to whether that review had occurred, and what the results would have been.

A. I'm not aware of it.

Q. Could you attempt to find out whether the review did occur, and if so --

MR. SNELSON: A. I think you can take it that a review did not occur, and we will get back to

you if that is not the case. But I'm pretty sure that one or the other of us would be aware of it if it had taken place.

Q. Panel, if you could turn to page 42 of Exhibit 137. That is figure 3.2 from the 1981 reliability review, Exhibit 140. Can you tell us how that figure was constructed and whether a model was used?

MR. TABOREK: A. I cannot.

MR. SNELSON: A. I have some recollection of how it was constructed, yes, but not the full details.

Q. Okay.

A. I believe there was a model.

Q. Perhaps you could get back to us on that.

A. I believe it was a two-area loss of load probability model.

THE CHAIRMAN: I'm having a little trouble hearing, Mr. Snelson.

MR. SNELSON: Sorry, I believe it was a two-area loss of load probability model, and that the modeling assumption was that Ontario Hydro was connected to a similar system via the interconnections. And one of the problems of these sorts of analyses is

that if we were to be connected, model ourselves as connected to the United States as one big pool, and that all of their surface reserve was available to us, then there would not be an appropriate sharing of the reserve benefit.

The best model we could come up with was that we could attribute a saving in reserve to ourselves from the interconnection that was about equal to the saving in reserve that we could contribute to the other side. This is an equal sharing of the benefit of interconnection.

Q. This figure seems to imply that the interconnection assistance depends on the lead time. Is this lead time the same as that which was used for the load forecast uncertainty?

MR. TABOREK: A. It is the same parameter, yes.

Q. When the lead time for load forecast uncertainty was reduced from eight years to four years, did you change the interconnection assistance assumption?

A. No.

Q. Why was that?

A. Because we felt it was attempting to -- you will note the changes that occur are small

and that it was not appropriate to try and discriminate to that degree of detail with an analysis of this type.

You will notice that this particular curve terminates in six years. Earlier, when we went to six to eight years, we didn't adjust the 700 megawatt number. Then coming back to the four years, you know, coming back from six to four, would give you roughly 100 megawatts additional, if you believed this analysis. And it was not really a strong basis, and it would be a small benefit.

Q. If you could turn to page 43 of Exhibit 137, that is 3.1 from the '81 reliability criteria, doing a plot of Ontario versus Michigan forecast errors, and I believe we have heard some evidence about the correlations between various systems.

Can you tell us how these correlations were explicitly accounted for in deriving the 700 megawatt assumption?

MR. SNELSON: A. They were explicitly accounted for in the sort of analysis that you saw on page 42 of Exhibit 137, the previous figure you referred us to, by assuming that the load forecast uncertainty was modelled in each of the two areas.

I said it was a two-area loss of load

probability, so the assumption was that the load forecast in our area was more or less correlated with the load forecast uncertainty in the area to which we are connected.

Clearly, the higher that degree of correlation, the more likely that when we are in trouble and need support over the interconnection, they are also in trouble and haven't got any support, any spare capacity to provide to us.

...

[4:07 p.m.] So, clearly, the higher the degree of correlation, then the less will be the interconnection support that can be relied upon when you really need it.

Q. So, in effect, that is your analysis and out of that comes a judgment?

A. Yes.

Q. Was there any kind of simulation performed or is this a pure judgment process?

A. Well, this sort of analysis could be termed 'a simulation.'

Q. Okay. Was there any mechanical simulation - any computer runs, anything like that?

A. This is a computer run.

Q. And is this an F&D run?

A. No. I believe it was a loss of load probability run. That is my recollection, but I would have to check that.

Q. All right. Now, has Hydro used the results of a multi-area reliability study in looking at the 700 megawatt assumption? You have mentioned --

A. This is a two-area study; and since two is part of multi, yes. But in the sense of more than two, no.

Q. Okay. Have they used a multi-run

reliability study?

A. I don't know what a multi-run reliability study is.

Q. You use various definitions of the study area and different runs in deriving the 700 megawatt assumption?

A. I don't recall any greater detail than I have given you, I am afraid.

Q. Okay. I would like to turn now to forecast uncertainty, with respect to NUGs and DSM.

Can you tell us how the DSM forecast is represented in the F&D model runs?

MR. TABOREK: A. Excuse me, but can you give the question again, please?

Q. Could you tell us how the DSM forecast --

A. Demand management?

Q. Yes - the demand management forecast is represented in the F&D model?

A. It subtracts from the basic to give the primary load and then to the firm load. And of particular importance, we make an assumption that the absolute megawatt uncertainty in the basic load forecast is not changed by demand management in going to the primary.

Q. Is the DSM forecast represented as one or more generating units, for instance, or is it represented as, say, a deduction from hourly loads?

A. I believe it is a deduction in going from the basic to the primary load, but I will check that.

Q. Okay. And could you also tell us whether the deductions are median expected values or some other values?

MR. SNELSON: A. The deductions of the forecast values that are included in our demand management projections?

Q. They are the target values?

A. They are the projected values, which are the difference between the basic load forecast and the primary load forecast.

Q. Is any uncertainty in the DSM forecast included in the F&D model runs?

A. Only as described by Mr. Taborek, where he said that the demand management is presumed not to widen or to narrow the uncertainty band of the basic load forecast.

Q. I am trying to think through that. I am not sure whether that answers my question.

I was wondering whether the demand

uncertainty was included. And you said to me that the uncertainty in going from the basic to the primary doesn't change.

Can I make a simple assumption that --

MR. TABOREK: A. If we state it very simply, it is included, but it doesn't have a big effect.

Q. Okay. Thank you.

How is the NUG forecast represented in the F&D model run?

A. Well, the supply NUGs, of course, are generators.

Q. Yes.

A. And the load some placement NUGs --

MR. SNELSON: A. Are part of the deduction from the basic load forecast to the primary load forecast.

Q. In the same way they would be a deduction from the hourly loads?

A. Yes.

Q. Thank you.

With respect to the supply NUGs only, how many units are accounted for?

MR. TABOREK: A. What do you mean by "units"; how many generators?

Q. Sure, yes. How many NUG units?

A. Well, they are modelled as small generators.

Q. Yes.

A. I forget the actual size - so that the benefits of small size are captured.

Q. Could you attempt to find out for us?

A. Yes.

Q. Thank you.

And Mr. Taborek, while you are looking at that, if you could also find the answer to these questions: I am interested in the forced outage rates assigned to the various units and --

A. The NUG units?

Q. Sorry?

A. The various NUG units?

Q. Yes.

A. Ten per cent.

Q. Ten per cent?

A. Yes.

Q. Okay. And also, how the maintenance requirements are represented.

A. Yes.

Q. I would also be interested as to whether the NUGs are grouped according to any

particular classification, such as by technology, by ownership or any other factors.

A. Yes.

Q. Thank you.

And I have the same question with respect to uncertainties, whether the NUG uncertainty is included in the F&D model run.

Would the answer be the same?

A. Yes. I think we have answered both of those.

Q. Okay.

MR. SNELSON: A. The NUGs are given a forced outage rate, and that is the measure of uncertainty of purchased NUGs that is given.

Q. Okay. I would like to turn to the subtopic of lead time, if you could look at page 41 of Exhibit 137, which is Table 4.5 from Exhibit 87.

THE CHAIRMAN: Did you say 41?

MR. WATSON: Yes, page 41 of Exhibit 137.

THE CHAIRMAN: Right. I have got it here.

MR. WATSON: Q. The standard deviation of the load forecast uncertainty is dependent on the lead time.

In the F&D model, does the load forecast

uncertainty ramp up from some initial value to 8.8 per cent from zero to four years?

MR. SNELSON: A. Yes, I believe it does.

Q. Is the standard deviation held constant at 8.8 per cent for every year after four years?

A. Yes.

Q. You don't need to turn it up because I think we all remember it very well, Figure 5.1 from the '91 reliability review.

I assume that there was a four-year lead time assumption used in deriving the load forecast uncertainty for these curves; is that fair?

MR. TABOREK: A. Yes.

Q. Okay. And I assume that is based on the lead time for gas turbine; is that correct?

A. Yes.

Q. Okay. What statistics do you have to determine four-year lead time?

A. I believe is reported in Chapter 14 of the Demand/Supply Plan, and it is, in essence, the result of discussions with our engineering and supply departments and their discussions with suppliers.

Q. Okay. Do you know if other utilities are actually building gas turbines within this

four-year lead time?

MR. SNELSON: A. The construction time of a gas turbine is given in figure 15-6 of Exhibit 3.

For a non-convertible and a normal cycle gas turbine, assuming that all approvals have been obtained - and this is a very significant point - the acquisition time is given of one to two years.

Now, that does presume that the order books of the manufacturers are not backed up as may occur if all utilities run to buy combustion turbines at the same time.

Q. And that might occur if there was a high degree of correlation between various utilities?

A. That might, but you notice that is one to two years.

The definition phase, which is the obtaining of the specific site approval, and the engineering work for a combustion turbine facility is shown as having a lead time of one to three years with a total of two to five. So then, four years is within that two- to five-year range and slightly towards the upper end of it.

Q. Okay. I was curious as to whether you are aware of other utilities which had actually built gas turbines within that lead time. Do you have

any information on that, or does Hydro have any statistical data?

A. Non-utility generators manage to buy combustion turbines and install them in less than that time.

Q. So you have information about NUGs as opposed to other utilities then?

A. We probably have information about other utilities, but I don't have it available to me.

MR. TABOREK: A. Our engineering and supply departments would have made those checks in developing these estimates.

Q. Okay.

A. We didn't, personally.

Q. And to meet that lead time, of course, I assume you would be helped by obtaining pre-approvals if possible?

MR. SNELSON: A. I think it is essential that we have the approvals in principle of rationale and need for the combustion turbine parts of our plan, both the conventional combustion turbines and combined cycle and IGCC to put us into the position of being able to respond in a four-year lead time.

Q. I assume you would also have to do some pre-ordering of equipment?

A. We should be able to order equipment and have it installed in the four-year lead time, presuming that the order books are not backed up at the manufacturers.

Q. Would the site have to be selected before this four-year lead time?

A. Possibly not. The definition phase is intended to cover the site-specific approval phase and the preliminary engineering; and the site specific approval phase does include site selection.

Now, that is probably sufficient time if the selected site is one of the sites that we currently own. Combustion turbines can be added to our existing generating plant sites with relatively modest impact. It may not be sufficient time if it was necessary to go out and acquire new sites.

This type of discussion as to exactly how long these processes take would probably be better addressed to Panel 8 on the fossil-fueled options.

Q. Okay. Panel, if you could turn to page 44 of Exhibit 137; that is page 116 of Exhibit 87 and that mentions the role of the target reserve margin in estimating avoided cost.

...

[4:22 p.m.] Currently, does the "worth of adding a CTU" from Figure 5.1 play a direct role in the determination of avoided capacity costs?

A. Direct, no; indirect, yes.

Q. Could you elaborate on that, please, Mr. Snelson?

A. The capacity cost that is presumed for quite a large part of the period in determining avoided costs is the cost of adding a combustion turbine unit to the system, and that is based on the same estimate of the cost of a CTU as in this analysis.

We are going to talk about avoided costs a lot in the next panel, I believe.

Q. I understand. Currently, does the same factor, the worth of adding a CTU, play a role in evaluating avoided capacity costs in years before the first major supply addition is needed?

A. Yes.

Q. And again, can you elaborate upon that?

A. In a lot of the avoided cost calculations -- and again, I don't want to get into Panel 3 matters --

Q. I understand. If we can deal with it just generally.

A. The presumption is that non-utility generation, demand management and hydraulic capacity that is within the plan amounts will have deferred combustion turbines, even in periods when we actually don't plan to build combustion turbines, because we have our demand management and non-utility generation and hydraulic in the plan, which is the short-term, say the next 10 years.

Q. Now, currently, does the worth of adding a CTU play a role in evaluating avoided capacity costs in years before any new demand or supply resources are required, specifically before the year 2000 in the low-demand scenario, and here I am constrasting, in this question, demand management and NUGs with the major supply options that you were just addressing?

A. I don't recall at the moment exactly what the treatment is of capacity costs in the avoided cost evaluation and the low demand scenario, but that will be discussed in Panel 3.

Q. There are five major supply plans. Has Hydro run these plans in the F&D model and compared the estimates of, for instance, voltage reductions and other emergency actions?

A. Which major supply plans are you

referring to?

Q. The five in the D/SP.

A. And the question was?

Q. Has Hydro run these five plans in the F&D model and compared the estimates of voltage reductions and other emergency actions?

A. I believe that what we have run is some preliminary cases that are reported in Chapter 3 of the plan analysis, which I believe is Exhibit 6, and the runs that are in Exhibit 87, which are essentially based on Plan 15, which is the proposed plan.

I am not aware of runs having been done on the other scenarios, the other plans. That's F&D runs.

MR. WATSON: Thank you.

Mr. Chairman, that basically takes me through reserve margin. I was going to turn to some of the other major areas, but I notice that it is almost 4:30 and you wanted to stop at 4:30.

THE CHAIRMAN: How much longer do you think you will be?

MR. WATSON: That is where the difficulty comes in, in estimating this.

THE CHAIRMAN: I know. How many more subjects do you have to cover, perhaps put it that way?

MR. WATSON: There are three major subjects and a few minor subjects. The major subjects are plant life extension, environmental issues and plant performance. I am pretty sure that plant performance issues, or at least a lot of them, may be deferred to a later panel based on what Mr. Snelson was saying this morning.

THE CHAIRMAN: You might be able to discuss that with Mrs. Formusa, that might make it easier for you to do your preparation, if you could come to some agreement.

MR. WATSON: I will talk with Mrs. Formusa as soon as we break.

THE CHAIRMAN: So you think you will be part of the morning, anyway, on Monday?

MR. WATSON: It is a function of what happens.

THE CHAIRMAN: Of course it is. I am not trying to press you; I am just trying to get some rough idea.

MR. WATSON: We could easily be all day Monday, dealing with these questions. I don't want to mislead you.

THE CHAIRMAN: Mr. Rodger, you are next?

MR. RODGER: Yes. Mr. Watson has

actually covered some of the ground that I intended to cover, but I would anticipate still being around a day.

THE CHAIRMAN: Mr. Adams?

MR. ADAMS: Thank you, Mr. Chairman. Unfortunately, counsel couldn't be here.

We expect, pending the outcome of this cross-examination, particularly production forecast reliability, and whatnot, to be approximately a day and a half to two days.

THE CHAIRMAN: And you follow? I have just forgotten now. You follow... ?

MR. ADAMS: We follow AMPCO and IPPSO follows us, as I understand it.

THE CHAIRMAN: Where did we put Dofasco?

MS. MORRIS: After Ontario Natural Gas.

THE CHAIRMAN: All right. We will adjourn until Monday morning at ten o'clock.

THE REGISTRAR: This hearing will adjourn until Monday morning next at ten o'clock.

---Whereupon the hearing was adjourned at 4:30 p.m. to be resumed on Monday, May 27, 1991, at 10:00 a.m.

JAS/RT/JB